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Rebuttal 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-2)

Final Program Cost
Recent NRC Issues
Program Management
LCM/EPU Cost Separation Analysis

August 26, 2014

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy J. O'Connor. I am the Chief Nuclear Officer ("CNO") for Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"). The Company is a wholly-owned utility operating company subsidiary of Xcel Energy Inc. I am responsible for all nuclear activities at the Monticello Nuclear Generating Plant ("the Plant" or "Monticello") and the Prairie Island Nuclear Generating Plant ("Prairie Island").

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I provided Direct Testimony, Exhibit ___ (TJO-1).

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to address issues raised in the July 2, 2014 Department of Commerce, Division of Energy Resources' ("Department") Direct Testimony related to the Company's prudent implementation of the Life-Cycle Management ("LCM") and Extended Power Uprate ("EPU") program ("LCM/EPU Program", "LCM/EPU Project", "Project", or "Program") at Monticello. Specifically, I will address the following issues:

- The benefits of the LCM/EPU Program;
- The accounting and final costs for the LCM/EPU Program;
- Nuclear Regulatory Commission ("NRC") communications during licensing and recent NRC issues at Monticello;

- The prudence of the Company's management of the Program; and
- The allocation of costs between LCM and EPU.

II. LCM/EPU PROGRAM BENEFITS

Q. AFTER REVIEWING THE DEPARTMENT'S DIRECT TESTIMONY, DO YOU HAVE ANY OPENING REMARKS THAT YOU WOULD LIKE TO MAKE?

A. Yes, I note that while the Department's witnesses are generally critical of the planning, management, and oversight that the Company provided for this Program, they do not identify any specific actions we took as imprudent.[1]

In addition, the Department witnesses have not criticized the results of the construction effort. We recognize that this Program was more costly and difficult than we had anticipated. But despite the challenges we faced, the work we completed was the right work to do and it was done well. Since start-up in 2013, we have not experienced any major mechanical issues with the equipment installed or modified during the Program. While we continue to encounter issues with license compliance, these issues do not reflect upon the operations of the Plant.

In addition, the Department witnesses fail to acknowledge the larger context in which this Program arose. Prior to being relicensed in 2005, many of the Plant's systems were operating at or near the margin. With relicensing came the responsibility to ensure that the Plant's systems could operate safely and reliably through at least 2030, with plenty of margin to support operations

[1] In the Department's response to the Company's Information Request No. 8, Department consultant Mr. Mark W. Crisp stated that he did not determine that Xcel Energy's actions were imprudent. Exhibit __ (TJO-2), Schedule 1.

beyond that date if all necessary regulatory approvals can be obtained. The work that we completed was necessary to address component aging and obsolescence while restoring, as well as improving, operating margins to ensure safety and reliability for the long-term. The Plant has greater safety margins and is now safer and more reliable as a result of the work we did.

As described more fully in Company witness Mr. David M. Sparby's Rebuttal Testimony, it is also important not to lose sight of the value we provided to our customers and to the State of Minnesota with this Program. The work we completed supports the continued operation of approximately 671 megawatts ("MWs") of carbon-free generation until at least 2030 and potentially beyond.

Q. HAVE THERE BEEN ANY RECENT DEVELOPMENTS IN THE AREA OF REGULATION OF CARBON EMISSIONS SINCE FILING YOUR DIRECT TESTIMONY THAT COULD IMPACT THE NEED FOR CARBON-FREE GENERATION SUCH AS THAT PROVIDED BY MONTICELLO?

A. Yes. The Environmental Protection Agency ("EPA") released draft regulations on June 2, 2014 that would, for the first time, limit carbon dioxide emissions at existing fossil fuel-fired generating units and set state-by-state targets for reductions in greenhouse gas emissions. The EPA's draft rule has the potential to require Minnesota to reduce its carbon emissions by 40 percent by 2030. While these regulations are not final, they do underscore that nuclear facilities such as Monticello would be key to ensuring that the State of Minnesota can meet its carbon emissions target.

Q. In response to the Department's concerns about the overall condition of Monticello, what was the condition of Monticello prior to commencing the LCM/EPU Program?

A. Monticello commenced operations in 1970 pursuant to a 40-year operating license from the NRC. Prior to a legislative change in 2003, we anticipated that we would not be able to operate Monticello beyond the expiration of that initial license in 2010. As a result, we deferred major capital investments and upgrades to the extent possible, focusing instead on those investments necessary to operate Monticello safely until retirement in 2010. In addition, industry codes and standards changed and other plants that could seek license extensions undertook modernization efforts; Monticello did not.

Our capital budget for Monticello, from the mid 1990s until 2003, was kept to around only $5 million per year for non-regulatory capital projects. As the Department's testimony acknowledges, just prior to initiation of the Program, the book value of Monticello had depreciated to $153 million.[2]

Q. What did this minimal capital investment in Monticello mean for the Plant equipment?

A. This meant that, prior to the LCM/EPU Program, much of the Monticello power block side equipment was aging and in some cases obsolete, with increased wear rates reducing equipment operating margins. For instance, several key pieces of equipment were original plant equipment and had reached the end of their design operating life. This included four of the ten feedwater heaters which were original Plant equipment and two others which were 30 years old. These heaters were reaching their minimal code allowable

[2] O'Connor Direct at 43:16-18; Jacobs Direct at 4:1-2.

thickness. The equipment in a boiling water reactor ("BWR") tends to experience more wear as there is higher energy steam that passes through many components of the major equipment than the equipment in a pressurized water reactor ("PWR"). A PWR separates the water from the steam before sending the steam to the steam generator. This means that equipment in a BWR is subject to more erosion than that in a PWR.

The reactor feed pump motors and the condensate pump motors were also original plant equipment. The main power transformer and the 1AR transformer were also being managed to retirement as they were 40 and 60 year old units, respectively. Also, we operated many analog systems when the rest of the industry was moving to digital. A significant aspect of the LCM/EPU Program was to replace these aged and degraded systems and components.

Also, prior to initiating the LCM/EPU Program, we had not made any major improvements to the original 4 kV electrical distribution system that provides essential electrical service for Monticello's operation of both safety- and non-safety-related equipment. Given the electrical load additions that occurred over the first 40 years of Monticello's operation, we had an imminent need to add new electrical distribution capacity to increase margins and avoid overloading the existing electrical buses for safe operation beyond 2010.

Q. DO THE DEPARTMENT WITNESSES DESCRIBE ANY OF THE BENEFITS ACHIEVED BY THE PLANT?

A. Department witness Mr. Christopher J. Shaw acknowledges that the Program overall was cost-effective.[3] I am disappointed that Department consultants Mr. Mark W. Crisp and Dr. William R. Jacobs make no reference to Program benefits. While we do not dispute that the overall costs of the LCM/EPU Program were higher than we expected, we believe it is crucial that the Minnesota Public Utilities Commission ("Commission") also bear in mind the benefits we achieved as part of its consideration.

Q. WHAT ARE THE BENEFITS OF MONTICELLO'S LCM/EPU PROGRAM?

A. Mr. Sparby provides a discussion of the benefits accruing to our customers and the State. I will summarize the benefits to the plant and our employees arising from the costs that the Department consultants criticize.

- *Condensate Demineralizer System*. We replaced the old condensate demineralizer system that was operated through analog controls with a new automated, digital system. The old system required multiple manual valve manipulations while the new system automated and repositioned the system components to reduce the potential for human error. The old system required two plant a total labor time of 12 to 16 hours per week to clean the vessels. The total labor time for the new process is approximately four hours per week. Further, the new system more efficiently removes fine debris and resin from the condensate and as a result we expect reduced operations and maintenance costs.

[3] Shaw Direct at 15:3-5.

- *Electrical Distribution System*. Our addition to electrical distribution capacity allows us both to split the internal power needs (providing additional redundancy) and operate Monticello with substantially higher operating and safety margins and provide sufficient capacity to sustain existing and new electrical loads. This improved electrical performance reduces the likelihood of trips and forced outages. This new system will also ensure that we are able to meet evolving regulatory requirements after the events at the Fukushima Dai-ichi Nuclear Power Plant.

- *Power Range Neutron Monitoring*. The new Power Range Neutron Monitoring ("PRNM") System is a state-of-the-art system that allows us greater insight and information about Monticello's reactor core performance. Approximately 17 reactors of the 35 domestic BWR nuclear plants have modernized their PRNM System to the standard we now employ.

- *Feedwater Heaters*. Six of the ten feedwater heaters in the Plant were down to minimal code-allowable metal thickness. Replacing them allowed us to avoid substantial maintenance to re-tube them, avoiding longer re-fueling outages.

- *Reactor Feed Pumps and Motors*. The new reactor feed pumps and motors improved Monticello's operational reliability by addressing or eliminating issues related to the age and wear of the existing equipment.

- *Steam Dryer*. The new steam dryer is providing substantial benefits because it is more efficient at removing moisture from the steam produced in the reactor, reducing future operation and maintenance costs on larger components such as turbine blading.

- *Plant Operations*. We made design choices to be user-friendly to our NRC-licensed operators, by minimizing the number of new operator procedures for normal, abnormal, and emergency situations, such as implementing the two-pump solution for the reactor feed pumps and motors modification.

  Turbine. Our new turbine eliminated a higher vibration condition which added maintenance and monitoring expenses.

Q. DEPARTMENT WITNESS MS. NANCY A. CAMPBELL IDENTIFIES ISSUES AT MONTICELLO.[4] HOW HAS THE PLANT BEEN OPERATING SINCE THE 2013 OUTAGE?

A. The Plant has operated well since the final LCM/EPU Program modifications were placed in-service after the 2013 outage. The Plant experienced no faults or trips as it was brought back online after the conclusion of this outage, nor did it experience any trips or faults as it was brought back online after the 2009 or 2011 outages. The Plant has run well, operating at a 95 percent capacity factor this past summer. This was unusual when compared to other utilities that had significant adverse issues arise after installing major new equipment.[5]

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[4] Campbell Direct at 3:21-24.

[5] We have had some data collection and analysis issues relating to ascending from the previous 600 MWe to about 671 MWe as is now authorized by the EPU license. As I describe in my Surrebuttal Testimony in the rate case (Docket No. E002/GR-13-868) we are working with the NRC to address the issue. I expect that initial determinations of the significance of the outlier data will be made in the next few weeks. This has required adjustment to our ascension schedule, but I am optimistic this issue will be resolved.

Q. IS THIS TYPE OF SMOOTH TRANSITION FROM AN OUTAGE AFTER EPU MODIFICATIONS CONSISTENT WITH THE CONCERNS MS. CAMPBELL RAISES?

A. No. In looking at other nuclear plants across the country, several have experienced significant problems following installation of EPU upgrades. I summarize several of these examples below:

- St. Lucie experienced two plant trips following EPU upgrades;
- Turkey Point experienced a trip during generator testing as the plant was brought online following the EPU;
- Nine Mile Point experienced seal problems on their reactor feed pumps (including fires in the equipment). They were forced to reduce power several times after startup to address seal issues; and
- Grand Gulf experienced a plant trip during power ascension. The trip was tied to the ISO Phase Bus Duct Cooling, not EPU equipment. However, EPU equipment compounded the facility's response.

The smooth restart we achieved at Monticello after each outage is further evidence of the quality work and testing we performed.

Q. YOU MENTIONED THAT THE PLANT COULD CONTINUE TO OPERATE BEYOND 2030 BUT THE NRC LICENSE IS ONLY VALID UNTIL 2030, CORRECT?

A. That is correct. Our currently NRC license is valid until September 2030. I made this statement to note that some of the equipment we replaced as part of this Program was original plant equipment and had lasted 40 years prior to replacement. Based on the quality of work and equipment installed as part of the LCM/EPU Program, I expect that much of this equipment will last beyond the term of the license extension. If we obtain the necessary State and federal regulatory approvals to operate the Plant beyond 2030, the benefits of this Program for our ratepayers and our State will only grow.

I note that federal law and regulation governing the safety of U.S. nuclear reactors currently allow utilities to renew nuclear plant operating licenses for 20 years beyond their original, 40-year license term. The NRC and the nuclear industry are well underway to develop extended license policies to ensure that extending operating plants' lives beyond 60 years is safe, manageable, and economical. The NRC refers to this initiative as the "subsequent license renewal." I have attached a White Paper from the Nuclear Energy Institute discussing this initiative as Exhibit ___ (TJO-2), Schedule 2.

III. PROGRAM COSTS AND ACCOUNTING

A. Final Program Costs

Q. DEPARTMENT WITNESS MS. CAMPBELL STATES THAT AS OF MARCH 31, 2014, THE COMPANY ESTIMATED THE TOTAL COSTS FOR THE LCM/EPU PROJECT AT $748.1 MILLION (INCLUDING ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ("AFUDC")) ON A TOTAL COMPANY BASIS. IS THIS CORRECT?

A. Yes. On May 7, 2014, in response to the Department's Information Request No. 88, the Company provided an estimate of the total costs for the LCM/EPU Project of $748.1 million. This $748.1 million includes $635.3 million for construction work in progress, $28.0 million for retirement work in progress ("RWIP"), and $84.8 million for AFUDC. This estimate also includes costs estimates for the work remaining in 2014 and anticipated vendor settlement amounts. I have included Attachment A to the Department's Information Request No. 88 that includes our aggregate cost numbers from August 31, 2013 through March 31, 2014 (including AFUDC) with my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 3.

Q. MS. CAMPBELL REQUESTS THAT THE COMPANY FILE AN UPDATE ON THE FINAL COSTS FOR THE PROJECT IN ITS SURREBUTTAL TESTIMONY. WILL THE COMPANY PROVIDE SUCH AN UPDATE?

A. Yes. That submittal will include an explanation of any differences between these costs and the cost estimates provided in March 2014.

B. Single Work Order

Q. MR. CRISP CRITICIZES THE COMPANY'S USE OF A SINGLE WORK ORDER AS EVIDENCE THE PROGRAM WAS NOT "WELL-STRUCTURED."[6] WHY WAS IT APPROPRIATE FOR THE COMPANY TO INITIALLY UTILIZE A SINGLE WORK ORDER FOR THIS PROJECT?

A. As Company witness Mr. Scott L. Weatherby describes in his Direct Testimony, when we commenced this Project, all of the costs were accounted for in a single common work order (number 10245258). Use of a single work order was appropriate at the initial stages of the Project given the strategic integrated approach to the overall initiative.

Q. PLEASE DESCRIBE HOW THE PROGRAM DEVELOPED AS A COMBINED AND INTEGRATED INITIATIVE AND NOT AS SEPARATE LCM AND EPU INITIATIVES?

A. The Governance Council approved the Monticello relicensing strategy after a July 2003 presentation. This presentation is attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 4.

[6] Crisp Direct at 27:17-23.

Several years later, the Company began looking at the two initiatives in more detail from a high-level strategy and accounting perspective. As we continued through the evaluation process and into 2006, the Company recognized that the initiatives were sufficiently overlapping that it was most efficient to combine the LCM work with the EPU Program in August of 2006. Information supporting the determination by the Financial Council to recommend a unified program to the Board of Directors is included with my testimony as Exhibit ___ (TJO-2), Schedule 5. As seen on the page marked NSP 0013150 in this Schedule, the budget item was initially presented to the Financial Council as the EPU initiative only, but was ultimately combined into the LCM/EPU Program for budgeting purposes before the Financial Council approved the recommendation to the Board of Directors. The Board approved a combined LCM/EPU Program in August 2006 for $274 million.

Q. DO YOU AGREE WITH DR. JACOBS' CRITICISM THAT THE UNIFIED INITIATIVE HAD VIRTUALLY ALL COSTS ATTRIBUTABLE TO THE EPU AND NOT THE LCM?[7]

A. No. We knew we had to undertake LCM modifications to the equipment and our work with General Electric showed that much of this same equipment would be impacted if we moved to uprate conditions. The separate efforts involved so much overlap, we believed this combined approach was both reasonable and necessary to implement the Project.

We identified some of these LCM modifications in our Independent Spent Fuel Storage Installation ("ISFSI") Certificate of Need Application, including replacement of feedwater heaters, replacing the generator rotor and rewinding the generator, cable replacements, steam dryer replacement, repairing or

[7] Jacobs Direct at 8:2-4.

replacing main steam and feedwater piping, and other capital improvements as shown in Exhibit ___ (TJO-2), Schedule 6.

At the time of the ISFSI application, we estimated those LCM projects to cost approximately $135 million. At that time we noted that this was only a representative list. Multiple LCM modifications were affiliated with multiple EPU modifications and we identified an opportunity to take advantage of the efficiencies of a joint initiative and streamline the overall capital workload at Monticello.

Q. ARE THERE ANY PROGRAM COSTS THAT WERE NOT INITIALLY ASSIGNED TO SPECIFIC CHILD WORK ORDERS?

A. Yes. Approximately $104.4 million were not initially assigned to a specific child work order but are attributed to common costs for the Program. It is the Company's practice for construction projects to direct assign whatever charges are identifiable as related to a specific subproject activity and to allocate the remainder as common costs related to support all activities. For the LCM/EPU Program, these common costs include design and engineering work, consulting work, and other activities, such as radioactive protection, staffing, and scaffolding that were undertaken to support multiple subprojects. The $104.4 million in common costs was allocated on a pro rata basis among the subprojects upon completion.

Q. MS. CAMPBELL RAISES A CONCERN ABOUT THE LEVEL OF COMMON COSTS AND THE TRANSPARENCY OF THE COMPANY'S SPENDING.[8] HOW DO YOU RESPOND TO THOSE CONCERNS?

A. The $104.4 million represents approximately 15.7 percent of the total LCM/EPU Program costs. This level of common costs for a project of this magnitude and scope, with multiple subprojects, is reasonable.

With more than 40 subprojects ultimately being included in the LCM/EPU Project, it is reasonable for 15.7 percent of the total costs to be either: (a) related to the overall equipment systems being modified, without being tied to specific equipment or subproject elements, or (b) supporting multiple (or all) subprojects. Additional information regarding the common costs for this Program are provided in the Company's response to the Department's Information Request Nos. 38 and 42 which are attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 7.

Q. MS. CAMPBELL ALSO TESTIFIES THAT THE COMPANY'S USE OF A SINGLE WORK ORDER MADE IT DIFFICULT TO TRACK COSTS FOR THE PROGRAM AND "DOES NOT MAKE SENSE TO [HER] AS AN ACCOUNTANT."[9] HOW DO YOU RESPOND?

A. I am not an accountant and Mr. Sparby provides a response to Ms. Campbell's concern. I note that in preparation for this case, we provided the Department with a comprehensive database to track and account for costs.

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[8] Campbell Direct at 18-22.
[9] Campbell Direct at 21:18-19.

Q. DR. JACOBS NOTES THAT THE MAJORITY OF THE CHILD WORK ORDERS ARE LABELED AS "EPU" WHILE THE COMPANY HAS CLAIMED THAT A MAJORITY OF THE WORK WAS ATTRIBUTED TO LCM. CAN YOU EXPLAIN THIS?

A. Yes. As I stated above, the Company viewed the LCM/EPU Program as a single integrated project to upgrade the entire plant to operate until at least 2030. We used the moniker "EPU" as a shorthand for the LCM/EPU Program as a whole.

This nomenclature was not meant to, nor does it, evidence that a particular modification or child work order was solely attributed to EPU. For example, the Department and the Company agree that the steam dryer modification was 100 percent LCM, yet the Company work order for this modification is labeled "EPU Steam Dryer Replacement." *See* Exhibit ___ (TJO-1), Schedule 7 at 1. By whatever label, the capital improvements we implemented are an important part of upgrading and maintaining an older nuclear plant.

IV. PRIOR EPU AT MONTICELLO

Q. IN HIS DIRECT TESTIMONY, MR. CRISP REACHES SOME CONCLUSIONS BASED ON THE PLANT'S PRIOR UPRATE (THE "1996/8 RERATE").[10] PLEASE EXPLAIN THE 1996/8 RERATE TO WHICH MR. CRISP REFERS.

A. From 1996 to 1998, the Plant underwent a modest rerate to take advantage of existing design margins at Monticello. The 1996/8 Rerate was the first EPU to be completed in the United States. This EPU increased the output of Monticello by approximately 6.3 percent of the original license thermal power.

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[10] *See* Crisp Direct at 5:20-25.

Q. WHAT WAS THE LEVEL OF ENGINEERING AND IMPLEMENTATION THAT WENT INTO THE 1996/8 RERATE?

A. The 1996/8 Rerate did not require significant physical modifications to the Plant. Rather, the 1996/8 Rerate was designed to allow us to capture additional capacity that was already available by confirming Monticello would continue to operate safely at the higher output level and make any necessary modifications while we were undertaking already-scheduled LCM efforts.

Q. WHAT PHYSICAL MODIFICATIONS TO MONTICELLO WERE MADE AS PART OF THE 1996/8 RERATE?

A. To achieve this new output level, in addition to calculation and operational analysis, the Company completed minor modifications that included:

- Tuning of water chemistry controllers;
- Changes to setpoints for the PRNM, annuciators, and main steamline flow;
- Increase condensate pump hotwell level;
- Recertification of feedwater heaters;
- Installation of drainlines and fresh air intake for the control room heating and ventilation;
- Replace all low pressure turbine components, including the inner casing, rotor, blades, and diaphragms; and
- Replace high pressure turbine.

Q. WHAT WAS THE COST OF THE 1996/8 RERATE?

A. The 1996/8 Rerate was done primarily through operation and maintenance expenses. The 1996/8 Rerate cost $4.5 million in operation and maintenance costs and $31.2 million in capital expenses. The expenses included $30.6

million associated with the turbine that were required to support continued plant operation and costs associated with unit efficiency improvements and rerate steam flows. The investment in the 1996/8 Rerate reduced the cost to operate Monticello as it increased the generation of Monticello at a very low capital cost.

Q. MR. CRISP COMMENTS THAT "AS-BUILT" SUMMARIES OR CONDITIONS SHOULD HAVE BEEN PREPARED OR KNOWN AS PART OF THE 1996/8 RERATE.[11] IS HE CORRECT?

A. No. Mr. Crisp's statement that as-built summaries or conditions should have been prepared or should have been known because of the 1996/8 Rerate is not a reasonable conclusion. The 1996/8 Rerate required very minimal actual construction work and was primarily achieved through calculations. For the most part, the 1996/8 Rerate was accomplished through calculations that allowed us to capture capacity that Monticello was already physically able to produce. The only major modification for the 1996/8 Rerate were the high- and low-pressure turbines. I note that the turbine modification during the 2009 outage was not impeded by lack of as-built drawings. In response to Company Information Request No. 6, attached to my Rebuttal Testimony at Exhibit ___ (TJO-2), Schedule 8, Mr. Crisp provided a list of documents that he referred to in making his statement regarding as-built drawings. The Monticello-specific documents Mr. Crisp references in this response do not require further development of as-builts beyond those that have been prepared to date. I address the documents that are not Monticello-specific as follows:

[11] Crisp Direct at 5:20-22.

- *NRC QA Program Procedure 35742B* sets forth the requirements for existing as-built drawings and the procedure for addressing discrepancies as they are found. Non-conformances and installation of mechanical items do require revisions to as-builts. No as-built development beyond what was already done under the 1996/8 Rerate is required by this procedure.

- *NRC Inspection Procedure 37051, 10 CFR 52, and ANSI N45.2* apply to facilities that began operation after Monticello received its operating license.

- *10 CFR 50* applies to safety-related components whereas the modifications during the 1996/8 Rerate and LCM/EPU Program were primarily non-safety-related.

Q. IN YOUR EXPERIENCE, IS IT UNUSUAL THAT AS-BUILTS ARE NOT READILY AVAILABLE FOR ALL SYSTEMS AT MONTICELLO?

A. No. When first-generation nuclear plants were constructed, as-built configuration drawings of non-safety-related plant systems were not fully developed. This was because many mechanical systems were field run, meaning craft labor determined the routing during installation, to expedite installation. When Monticello was constructed in the late 1960s, little consideration was given to potential future major upgrades and it was assumed that the original equipment would last the duration of the license.

In the 1980s, Monticello committed to verify electrical systems on as-builts when we completed Plant modifications. This mitigates the risk of electrical systems not properly documented at the time of construction. This commitment does not apply to other non-safety-related systems. However, in 2008, Xcel Energy adopted the approach to update all as-built drawings whenever it undertakes a project within the Plant. This standard procedure now documents mechanical, electrical, and civil as-built conditions when discrepancies are found in these non-safety-related systems but does not to create fully developed as-built plans absent a modification to the equipment. We provide detail on Xcel Energy's experience with as-built drawings in the Company's response to the Department's Information Request No. 27, attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 9.

V. NRC COORDINATION AND COMMUNICATIONS

A. NRC Interaction Through Licensing Process

1. Communications

Q. DEPARTMENT WITNESS MR. CRISP ASSERTS THAT THE COMPANY SHOULD HAVE MAINTAINED EXTENSIVE COMMUNICATION WITH THE NRC DURING THE LICENSING PROCESS.[12] WAS THIS THE CASE?

A. I first want to point out that Mr. Crisp does not assert that the Company failed to do this, although a cursory review could lead one to incorrectly assume this is what he meant. I agree with his observation that extensive communication is important and want to dispel any implied suggestion that this was a shortcoming by the Company.

[12] Crisp Direct at 15:8-12.

Q. DESCRIBE THE COMPANY'S COMMUNICATIONS WITH THE NRC REGARDING THE LCM/EPU PROGRAM.

A. The Company communicated extensively with the NRC during the licensing process. A log of the Company's major communications with the NRC related to the EPU License Amendment Request is attached to my testimony as Exhibit ___ (TJO-2), Schedule 10. This communication log has over 231 entries spanning from 2007 to 2014 and does not even include all of the informal contacts between the Company and the NRC.

Q. WHAT COMMUNICATIONS WITH THE NRC ARE NOT INCLUDED IN THIS COMMUNICATION LOG?

A. This log does not list routine communications that the Company had with the NRC. For example, brief discussions between Company personnel and the NRC on the status of information requests, meeting preparations, or, in some cases, even technical feedback are not included in this log. I also note that between July 2011 and March 2013 we held weekly calls with the BWR Owners' Group, that sometimes include NRC personnel, to go over technical approaches related to containment accident pressures ("CAP") analysis. These weekly calls are not listed on the log. Also, we were not able to retrieve a full set of communication records prior to September 5, 2009, as certain key personnel involved with NRC communications at that time are no longer with the Company.

Q. THE DEPARTMENT CRITICIZES THE COMPANY FOR NOT DISCLOSING IN OUR 2005 LICENSE RENEWAL APPLICATION TO THE NRC THE POTENTIAL FOR AN EPU AT MONTICELLO.[13] HOW DO YOU RESPOND?

A. Describing an uprate in the license renewal application would have been contrary to NRC policy. The NRC will only process one application at a time. Also, we did not have internal authorization to move forward with the uprate then. Had we mentioned any uprate in our 2005 license renewal application to the NRC, this would have been inconsistent with the status of our evaluations and potentially prejudiced the review of our license extension application.

2. Steam Dryer Issue

Q. MR. CRISP ALSO TESTIFIES THAT THE COMPANY'S WITHDRAWAL OF ITS LICENSE AMENDMENT REQUEST IN JUNE 2008 IS EVIDENCE OF POOR PLANNING AND "MANAGEMENT INDECISIVENESS" BY THE COMPANY.[14] CAN YOU EXPLAIN WHY THE COMPANY WITHDREW ITS INITIAL REQUEST?

A. Our withdrawal was not the result of poor planning or indecisiveness; rather it was the result of the increased level of detailed engineering analysis required by the NRC for our initial proposal to modify rather than replace the existing steam dryer. I explain this issue extensively in my Direct Testimony[15] but Mr. Crisp does not acknowledge that explanation.

Q. DESCRIBE THE WORK THAT THE COMPANY UNDERTOOK THAT SHOWS MR. CRISP'S CRITICISM TO BE UNFOUNDED.

A. The Project team did significant due diligence and background work to understand the regulatory requirements of a nuclear uprate prior to submitting

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[13] Crisp Direct at 13:13-27.
[14] Crisp Direct at 14:1-7.
[15] O'Connor Direct at 53-55.

the initial License Amendment Request. We met in person with the NRC three times in 2007 and 2008 during the application-creation process. The first meeting was used to meet formally with the NRC Staff and gain the NRC's input on the best method to prepare the License Amendment Request. The second two meetings were devoted to steam dryer analysis methodologies. The NRC Staff did not raise any significant technical concerns with our proposed steam dryer modifications or our supporting engineering analyses.

Q. WHAT CAUSED THE NRC TO CHANGE ITS APPROACH TO STEAM DRYER MODIFICATIONS?

A. In March 2008, approximately two weeks before we submitted our initial License Amendment Request, the Advisory Committee on Reactor Safeguards ("ACRS") effectively requested an increase in the level of scrutiny for the steam dryer structural analysis by increasing the minimum acceptable stress ratio. We discussed this change with management and it was unclear whether or not the ACRS ratios would be applied by the NRC to our Plant. We made the decision to proceed with our initial License Amendment Request.

Q. HOW WAS THE STEAM DRYER ISSUE WITH THE NRC RESOLVED?

A. Ultimately, based on continuing changes to steam dryer analysis requirements by the NRC, we decided to replace, rather than modify, the existing steam dryer. The Company met with the NRC again in October 2008 and resubmitted the EPU License Amendment Request to the NRC on November 5, 2008. In 2009, we continued our work on the steam dryer design and procurement. We also continued to work with the NRC and responded to

Requests for Additional Information ("RAIs") during this time. On February 18, 2010, we notified the NRC of our intent to install a new steam dryer.

After we decided to replace the steam dryer, the NRC began to focus on whether the structural analysis of the new steam dryer was sufficient. The review of the new steam dryer included numerous iterations of the analyses. This was the last substantive issue to be resolved with the ACRS in September 2013.

Q. DID THE DECISION TO REPLACE THE STEAM DRYER INCREASE COSTS FOR THE PROGRAM?

A. Without question, yes. The decision to replace the steam dryer resulted in a Project cost increase of $31 million for the dryer and approximately $3.5 million for repairs to strain gauges used to monitor steam dryer loads, repairs to accelerometers used to monitor piping vibration, and removal of steam dryer instrumentation.

3. Licensing and Calculation Costs

Q. DR. JACOBS TESTIFIES THAT EVOLVING NRC REGULATIONS, IN PARTICULAR THOSE RELATED TO THE CAP ANALYSIS, AND THE EVENTS AT FUKUSHIMA DID NOT IMPACT THE PROGRAM SCHEDULE.[16] DO YOU AGREE WITH THIS ASSESSMENT?

A. I agree with Dr. Jacobs that the Company was not able to complete the Program by 2011 and the delay in licensing did not delay the ability of Monticello to ascend to uprate operating conditions. It is, however, important to note that the delay in the license did add to our licensing costs. We spent

[16] Jacobs Direct at 15:9-23.

over $50 to $80 million more in licensing costs than we originally anticipated, depending on whether you use 2006 or 2008 estimates as the starting point. While not the primary driver of Program cost increases, this increase is certainly notable.

Q. DR. JACOBS NOTES THAT THE DELAY IN LICENSING DID NOT CHANGE THE CAPITAL COSTS FOR THE PROGRAM AND THAT COSTS OF THE NRC REVIEW WERE MINOR.[17] HOW DO YOU RESPOND?

A. Overall, the evolving NRC regulations were a significant driver in the costs we incurred for the Program. While we did not separately track costs to specific NRC requirements, we incurred additional licensing and design costs necessary to demonstrate Monticello's compliance with the relevant regulatory requirements. Also, increasing NRC scrutiny related to analysis of existing steam dryers resulted in our decision to replace rather than modify our steam dryer. Table 1 provides our estimate for the these increased costs.

Table 1. NRC Related Costs for the Program

Cause	Cost
Increase in Licensing Costs	$30+ million (increase over 2008 estimate
Additional Calculation Costs	$16+ million
Addition of New Steam Dryer	$30+ million (added to scope after 2007 authorization)
Addition of Monitoring Equipment	$7 million (added to scope after 2007 authorization)
CAP Issues	$1 million

[17] Jacobs Direct at 15:11-13.

The CAP issues contributed to a four year delay in our license schedule. I discuss the schedule impacts in further detail after I explain the increase in licensing costs during the Project.

Q. EXPLAIN WHY LICENSING COSTS INCREASED DURING THE PROGRAM.

A. The NRC's licensing process required an iterative engineering process to demonstrate the Plant's ability to operate safely at uprate conditions. To obtain approval of our License Amendment Request we had to demonstrate that Monticello would remain within its safety limit under the revised licensing basis and the planned operating limits would remain within the licensing basis for the facility. An initial review of each structure, system, or component needed to be revised when a connected or supporting system required a change that impacted the original structure or system.

During the 2000s, the NRC determined that a higher standard is expected for new EPU license amendment submittals as compared to previous submittals. In total, we received and responded to more than 460 RAIs pertaining to the EPU and Maximum Extended Load Line Limit Analysis ("MELLLA+") License Amendment Requests. Despite the NRC's stated 12-month target time to process a License Amendment Request, ours was pending with the NRC for more than five years.

The Company did not attempt to track costs associated with the changing regulatory regime over the course of the Program. Overall, however, our design and engineering costs were approximately $158.8 million,[18] which included both expected design costs and a significant portion attributable to

[18] O'Connor Direct at 6, Table 2.

the numerous iterations necessary to demonstrate Monticello's operating ability.

Q. HOW DID THE COMPANY TRY TO MINIMIZE LICENSING COST INCREASES?

A. We worked with contractors to identify the licensing issues that needed to be addressed. Those issues were identified based on a review of all Monticello-specific design and licensing basis requirements, permits, available EPU operating experience, and regulatory issues as found in ACRS transcripts and NRC notices, and areas of review contained in NRC Review Standards for EPUs, RS-001. Xcel Energy's Project team also reviewed NRC RAIs and responses for previous licensees to identify the industry issues that concerned the NRC staff.

The Project team did significant due diligence and background work to understand the regulatory requirements of a nuclear uprate. During the NRC's review of our application, we communicated with the NRC regularly regarding schedule, scope, and upcoming events. We also met at least 20 times with the NRC in person and had at least 61 additional conference calls with NRC technical reviewers over the course of the NRC's review.

Q. EXPLAIN WHY THE COMPANY INCURRED ADDITIONAL COSTS RELATED TO CALCULATIONS TO SUPPORT THE NRC LICENSING EFFORTS.

A. Additional calculations were required due to the revision to our calculation fleet procedures after issues were raised during an NRC Region III inspection. Initial Project estimates assumed that we could make a targeted change when making a major revision to a calculation. This would have allowed changing only that portion of the calculation that was impacted. The fleet procedure change required validation of all inputs and assumptions used when any major revision occurred. This change resulted in reconstitution of the design basis for these type of revisions.

In some cases, correction of previously existing legacy issues substantially increased the required number or complexity of calculations impacted by the Program. Because we were required to comply with all of the requirements for providing revised calculations, the change resulted in a threefold increase in the amount of work necessary to complete approximately 500 major calculations. In addition, a substantial increase in the total population of calculations occurred from the 1996/8 Rerate, and this calculation procedure change resulted in the need to perform a complete reconstitution of the high-energy line break, motor operated valve, air-operated valve, and equipment qualification programs and substantial changes associated with instrument setpoint methodologies. The costs associated with a significant portion of the calculation work was tracked in five work orders as shown in Table 2.

Table 2. NRC Calculation Work Orders

Project Modification	**Work Order**	**Final Costs**
High-Energy Line Break	11636097	$4,778,454
Environmental Qualification	11636101	$2,522,236
Instrument Service Requirements	11636105	$2,144,441
Motor and Air-Operated Valves	11636109	$2,582,437

Project Modification	Work Order	Final Costs
Stress Analysis for Piping	11636114	$4,052,729
Total Cost (without AFUDC & RWIP)		**$16,080,297**

We describe further information on the calculation requirements in the Company's response to the Department's Information Request Nos. 59, 60, and 62 attached to my testimony as Exhibit ___ (TJO-2), Schedule 11.

Q. WHAT DID THE COMPANY DO TO TRY TO MINIMIZE ADDITIONAL DESIGN AND CALCULATION COSTS?

A. The Company used internal resources with substantial experience at Monticello to the extent possible for conducting the additional calculations required by the NRC to minimize the added costs.

4. CAP Impacts

Q. EXPLAIN HOW ISSUES RELATED TO CAP IMPACTED COSTS AND SCHEDULE FOR THE PROGRAM?

A. Monticello was approved to use CAP credit under our license basis and we used these requirements in our submission. Our analysis showed that our operations would remain within the original requirements at uprate conditions with no additional NRC approval. Our approach was consistent with the approach of other utilities seeking EPU approval and CAP credit granted by the NRC in earlier EPU license amendments. This included NRC approval of a plant-specific licensing action related to net positive suction head ("NPSH") that was approved as recently as December 9, 2013.

Q. WHAT CHANGED AFTER THE COMPANY SUBMITTED ITS LICENSE AMENDMENT REQUEST IN NOVEMBER 2008?

A. Shortly after we submitted the License Amendment Request, use of CAP in determining the available NPSH was challenged by the ACRS, by participants in the NRC hearing process, and members of the public, who raised the possibility that the practice of using CAP credit could result in the degradation of the regulatory defense-in-depth philosophy. In March 2009, the ACRS recommended industry-wide changes to the practice of including CAP credit in NRC-approved licenses until resolution of areas of disagreement between the staff and the ACRS could be obtained. In October 2009, the NRC officially informed the Company that the agency required more time to ensure the technical adequacy of the Company's application, which would result in delays in the staff's review of the application.

The Company worked diligently to move the issue forward, and did so successfully just as the events of Fukushima unfolded. The CAP issue changed quickly after that date and the NRC staff indicated it would need significant additional analysis of the emergency core cooling system ("ECCS") pumps and more review time to assure appropriate resolution of this issue. In March 2011, the NRC added a new set of analytical requirements to determine the ECCS pump NPSH uncertainties and in April 2011, the NRC officially reactivated the review of the EPU License Amendment Request.

The CAP uncertainty analysis requirement was new to the entire industry and had never been implemented before. Monticello was the lead plant that had to develop and implement a computationally complex resolution. We pursued parallel paths to ensure a successful outcome, working collaboratively with the rest of the industry in the BWR Owners' Group, and also on its own independent analytical approach. To prepare the NPSH uncertainty analysis, in July 2011, the BWR Owners' Group retained a vendor to perform computational fluid dynamics ("CFD") evaluation of industry ECCS pumps. The CFD model was constructed of 15 million elements and required the use of up to several hundred computers running iterations simultaneously. In March 2012, the BWR Owners' Group determined that the use of the CFD model to test the ECCS pump design in use at the Plant was not feasible.

Simultaneous with the BWR Owners' Group efforts, Monticello worked to develop an analysis to support the use of CAP and satisfy all NRC requirements. The analysis we developed supported the continued safety and reliability of the ECCS pumps under all accident and event conditions. We submitted those analyses to the NRC in September and November 2012, and we responded to additional CAP RAIs in February and March 2013.

Q. HOW WAS THE CAP ISSUE RESOLVED?

A. The NRC approved our CAP analysis in 2013, marking the first time the industry has successfully addressed the CAP issue under the new NRC guidelines. More details discussing the CAP analysis with the NRC are provided in the Company's response to the Department's Information Request No. 75 attached to my testimony as Exhibit ___ (TJO-2), Schedule 12.

Q. How did the CAP issues impact cost and schedule for the Project?

A. In total, the CAP issue delayed NRC approval of the Company's licensing process by approximately four years and added direct costs of at least $1 million to the effort.

5. Fukushima Impacts

Q. Department witness Dr. Jacobs states that no costs specifically related to Fukushima impacted the LCM/EPU license effort.[19] Do you agree?

A. No.

Q. How did the events at Fukushima impact the cost and schedule for the Program?

A. The evolving regulatory requirements and the need to proactively manage our operating margins increased after the Fukushima incident. As mentioned above, Fukushima led to a more thorough review of CAP credit. In addition, the delay in approval led to additional RAIs that occurred as the license process extended through several staff changes. I believe the NRC staff's response was reasonably influenced by the events at Fukushima.

Q. In your Direct Testimony you discussed a connection between the 13.8 kV system and Fukushima.[20] Can you explain if this means you view the 13.8 kV system a compliance-related cost?

A. I do not consider the 13.8 kV system a Fukushima compliance-related cost. The purpose of discussing both the 13.8 kV system and Fukushima was to describe why our decision to upgrade to a 13.8 kV electrical distribution

[19] Jacobs Direct at 15:21-23.
[20] O'Connor Direct at 135:17-20.

system for the non-safety-related equipment turned out to be a very good solution for Monticello. I describe this issue in detail in my Direct Testimony.[21]

6. Conclusion

Q. DO YOU AGREE WITH MR. CRISP'S CONCLUSION THAT THE LICENSE AMENDMENT REQUEST PROCESS WAS LENGTHY BUT "NOT NECESSARILY DUE TO NRC DELAYS OR ADDED NRC REQUIREMENTS"?[22]

A. While I agree that the process to obtain the license amendment for Monticello was lengthy, Mr. Crisp's conclusion are over-simplified. As discussed by Mr. Crisp, our five-year licensing effort included approximately 63 official correspondences between the Company and the NRC and also included amending the previous Facility Operating License and a revision to the Technical Specifications.

I agree with Mr. Crisp that "this longer time period was appropriate for safety reasons"[23] but these represented changes to requirements or expectations of safety that were not present when we estimated the initiative. I also agree with Mr. Crisp's assessment of the extended analysis the Company was required to complete "as a result of the Company's reasonable decision to use the NRC guidance regarding the higher water temperatures."[24] As Mr. Crisp notes, Monticello was the first License Amendment Request to use this guidance and "it is understandable that the schedule was delayed and costs impacted" by this approach.[25] The information I provided in my Direct Testimony was

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[21] O'Connor Direct at 135-136.
[22] Crisp Direct at 12:1-4.
[23] Crisp Direct at 12:9-10 and 14:12-13.
[24] Crisp Direct at 14:15-16.
[25] Crisp Direct at 14:18-15:1.

included to explain the various details of this lengthy process and the impacts of the Plant's reasonable and appropriate decisions along the way.

B. Recent NRC Issues

Q. IN HER DIRECT TESTIMONY, MS. CAMPBELL NOTES THAT THE NRC HAS RECENTLY IDENTIFIED ISSUES AT MONTICELLO RELATED TO EXTERNAL FLOOD RESPONSE, IMPROPER WELDING, AND GENERAL HUMAN PERFORMANCE.[26] IS THE COMPANY ADDRESSING THESE ISSUES?

A. First, I want to emphasize that none of the items raised by Ms. Campbell constitute safety violations or otherwise created any risk to the community. Second, we take our NRC compliance obligations very seriously. We are working diligently to resolve each of these issues and we are making good progress. Third, increasing regulatory scrutiny means that we are called upon to bring our performance to a higher level. This is a challenge and we are learning as we adapt to this environment.

Q. DESCRIBE THE NRC ISSUE RELATED TO EXTERNAL FLOOD CONTROL AND HOW THE COMPANY IS ADDRESSING THIS ISSUE.

A. The NRC ordered increased scrutiny over natural disaster protection as a direct result of lessons learned from Fukushima. In response to this new requirement, NRC inspectors undertook flooding walk-downs at Monticello. The NRC inspector identified an external flooding concern focused on Monticello's capability to timely construct a wall along the river by Monticello's intake structure to preclude flood waters from impacting the safe operation of Monticello. In 2012, the Company revised its External Flooding Response Procedure to incorporate use of a large metal wall along with an

[26] Campbell Direct at 3:15-24.

earthen berm, to protect required plant safety equipment from the postulated external flood in accordance with Monticello's design and licensing basis. Use of the metal wall was a new action and the NRC questioned how long it would take to construct the wall because Monticello had not validated the time to construct the wall. The NRC concluded that Monticello made an inappropriate/non-conservative procedure change (requiring the wall installation) without understanding the impacts of the change. This conclusion led the NRC to issue a finding classified as "yellow" based on the safety significance.

Q. HOW HAS THE COMPANY RESPONDED TO THE YELLOW FINDING RELATED TO THE FLOODING ISSUE?

A. Monticello's external flooding procedure was corrected shortly after the concern was raised by the NRC. Materials were procured and delivered to Monticello site to ensure that construction times could be met. The External Flooding Procedure was revised to credit erection of the metal wall in a timely fashion such that the conditions specified in the operating license could be met. In its June 11, 2013 letter informing us of their preliminary yellow finding, the NRC acknowledged our action to reduce the flood mitigation plan timeline to less than 12 days by developing an alternate plan for flood protection features, pre-staging equipment and materials, improving the quality of the A.6 procedure, and preplanning work orders necessary to carry out Procedure A.6 actions. To close the yellow finding, the NRC is required by its procedures to conduct a follow-up inspection to ensure Monticello has addressed their concerns. We are awaiting this follow-up inspection to fully resolve the issue.

Q. WHAT IS THE WELD INSPECTION ISSUE THAT WAS IDENTIFIED BY THE NRC AND HOW IS THE COMPANY ADDRESSING THIS ISSUE?

A. Last October, during the spent fuel dry cask loading campaign, the NRC observed that a cask closure weld was not properly post-weld dye penetration inspected/examined. This brought into question the adequacy of cask closure and its ability to be transported off the refueling floor to the on-site storage facility. Since that time we have been working with the designer of the cask and the NRC on alternative methods to accept the cask closure welds. An Engineering Evaluation and weld design margin calculations were conducted by the vendor that supports the adequacy of the welds in lieu of post-weld dye penetration examinations. The weld design margin calculation and other evaluations and data were formally submitted to the NRC, under their Exemption Request process, on July 16, 2014. It will take the NRC several months to review the request and grant the Company permission to move the cask to the on-site storage facility. We are looking at options to conduct physical repairs should the Exemption Request not be granted.

Q. WHAT IS THE HUMAN PERFORMANCE RELATED ISSUE RAISED BY THE NRC AND HOW IS THE COMPANY WORKING TO ADDRESS THIS ISSUE?

A. The concern regarding human performance stems from several examples where human performance issues contributed to findings of low safety significance identified by the NRC. In aggregate, the NRC determined that these issues crossed the threshold for what the NRC calls a Substantive Cross-Cutting finding in the area of human performance. These human performance concerns were determined to be manifested in Inadequate Procedure and Work Instruction(s) preparation and usage. Many of the issues were attributed to a loss of experience and skills within the Operations

Department. Interim actions have been put in place by Monticello to bridge the gaps, such as additional Control Room Oversight and coaching.

Another area identified as a human performance issue was contractor procedure usage. During the recent EPU refueling outage, several thousand vendors were brought on-site to execute a very complex outage scope. At the time, it was discovered that supplemental workers had less nuclear experience than in the past. Although additional oversight was provided, contract workforce experience was a major contributor to the issues we encountered during the Program. We anticipate an NRC follow-up inspection on this issue in October.

VI. PRUDENT PROJECT MANAGEMENT

A. Preparations for LCM/EPU Program

1. *Cost Estimation*

a. Other EPU Projects

Q. THE DEPARTMENT'S CONSULTANTS ARE CRITICAL OF THE COMPANY FOR FAILING TO BE PREPARED FOR THE WORK AND THE DIFFICULTY OF THE JOB. DO YOU AGREE?

A. No. While there is no question the job turned out to be much more difficult than we expected, this was not caused by lack of preparation or poor planning. It is critical to keep in mind that the circumstances we encountered when the initiative was developed were far different than what we face today. It is easy in 2014 to look back and criticize decisions made in 2006 to 2008, but those criticisms must be grounded in what we knew at that time.

Q. PLEASE DESCRIBE THE COMPANY'S PREPARATION FOR THE INITIATIVE.

A. The Company had undertaken the 1996/8 Rerate, so we were generally aware of the issues surrounding increasing output from the reactor. Later, we started to work with the BWR Owners' Group to understand the experiences of others at that time. We reviewed this group's *Extended Power Uprate ("EPU") Lessons Learned and Recommendations* report. This gave us baseline information about how the industry was approaching uprates.

Through our contract operator/manager, Nuclear Management Company, we began to investigate the issues that had previously arisen in EPU work at other BWRs, such as issues with steam dryers and ECCS. We also adopted a series of programmatic controls for implementing the EPU based upon EPU lessons learned at other BWRs, including:

- Benchmarking trips and reports from other plants;
- Review of pending EPU applications;
- Participation in the BWR Owners Group committee on EPU;
- Review of the Lessons Learned process; and
- Consultation with General Electric and other industry experts.

Q. DID THIS WORK ADEQUATELY PREPARE THE COMPANY FOR THIS INITIATIVE?

A. We certainly thought so at the time but as it turned out our job was harder and much more expensive than any of the previous efforts at other plants.

Q. CAN YOU PROVIDE EXAMPLES OF DIFFERENT EXPERIENCES IN THE INDUSTRY?

A. Yes. First, units that we benchmarked were all able to complete their uprate work with far less effort than we experienced. Below, in Table 3, I lay out their experience. I also reproduce Table 3 from my Direct Testimony to contrast the more recent experience (including Monticello):

Table 3. Cost Increases and Schedule Changes

Project	Descrip-tion	Initial Cost Estimate	Latest Cost Estimate	Ratio of Final to Initial Cost	Estimate of Schedule Extension	Year Completed
Ginna	EPU	$33 million	$44 million	1.33	n/a	2006
Brunswick	EPU	$145 million + $2.5 million contingency	$180* million	1.22* (including contingency)	n/a	2002
Vermont Yankee	EPU	$75 million	$100 million	1.35	n/a	2006

* Progress Energy reported that the project cost nearly $180 million.

Exhibit ___ (TJO-1) 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

Q. WHAT DO THESE TABLES DEPICT?

A. During the timeframe in which we were deciding to proceed with the Program, uprate projects were coming in at costs within 133 percent of initial cost estimates. More recently, however, uprate projects have been coming in 160 to 220 percent of initial cost estimates.

Q. WHAT WAS THE COMPANY'S PERSPECTIVE ON COST AT THE BEGINNING OF THE INITIATIVE?

A. Our preparation was appropriate based on what we knew at the time and the experience of other utilities that had completed uprates around the time that we started our initiative. The difficulties we encountered were caused primarily by circumstances that we reasonably could not have foreseen at the time and evolving circumstances that made our job harder. We thought that we already accounted for some of the challenges we knew we would face during implementation, like the smaller footprint and high-dose environments of Monticello, by seeking Board approval of an amount 75 percent higher than the most expensive benchmarked plant.

Q. DID THE COMPANY HAVE ANY BASIS TO FORESEE THAT THE MORE RECENT UPRATES WOULD BE SO MUCH MORE EXPENSIVE AND TAKE LONGER?

A. No. I note that the most expensive of the benchmarked plants, Brunswick, was completed for $180 million and only about 20 percent over the initial estimate. When we set our initial budget of $274 million, we were already higher than the benchmarked projects and it was not reasonable for us to have thought our cost pattern would be significantly greater than those projects.

Q. DEPARTMENT WITNESS MR. CRISP CRITICIZES THE COMPANY'S USE OF CONTINGENCY DOLLARS IN THE BUDGET ESTIMATES.[27] DO YOU AGREE?

A. Yes and no. As discussed in the Company's response to the Department's Information Request Nos. 52, 54, and 68, contingencies were used throughout the Program. A copy of our responses to the Department's Information Request Nos. 52, 54, and 68 are attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 13. However, while I believe our effort to estimate contingency dollars was reasonable, it is possible we could have included additional contingency in our estimates. But the presence or absence of contingency does not make the overall cost of a project higher or lower.

Q. DID YOU HAVE ANY OTHER COMPARABLES THAT YOU CONSIDERED?

A. Yes, and again that led us to believe that the costs for our initiative would not increase the way they did. That comparable was the Duane Arnold plant in Iowa.

Q. DID THE COMPANY FORMALLY BENCHMARK AGAINST DUANE ARNOLD?

A. No. Formal data about Duane Arnold was not generally publicly available. However, through informal contacts we know that the uprate at Duane Arnold was undertaken in 2001 under a different regulatory environment and that it was narrower in scope than the work we undertook at Monticello.

It is our understanding that Duane Arnold planned to phase-in both its uprates and equipment enhancements over an extended time period and that this effort is still ongoing today. So it is difficult to benchmark as the timing and scope were so different.

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[27] Crisp Direct at 29:20-30:11.

Q. DO THE DEPARTMENT'S CRITICISMS OF THE COMPANY RECOGNIZE THESE FACTORS AND THE EVOLVING NATURE OF NRC REGULATION?

A. No. I have attached to my Rebuttal Testimony the Company's responses to the Department's Information Request Nos. 75 and 76, which provide more details on the changes to the NRC regulatory process after Duane Arnold had undertaken its uprate as Exhibit ___ (TJO-2), Schedules 12 and 14. I do not see that the Department's Direct Testimony addresses these issues.

Q. WHAT DO YOU CONCLUDE FROM THE CHANGES THAT HAVE OCCURRED IN THE INDUSTRY SINCE THE COMPANY BEGAN INVESTIGATING AN UPRATE.

A. I conclude that we acted reasonably when we started to investigate the job. We relied upon available precedent, worked through formal and informal industry contacts, and developed a plan that was consistent with what had come before. We could not have foreseen the dramatic changes that were going to occur and the additional costs that would arise out of those changes.

b. Brownfield vs. Greenfield Nuclear Construction

Q. MR. CRISP RECOGNIZES THAT THERE ARE KEY DIFFERENCES BETWEEN A RETROFIT PROJECT SUCH AS THE LCM/EPU PROGRAM AND A GREENFIELD OR NEW CONSTRUCTION PROJECT.[28] DO YOU AGREE?

A. Retrofit projects at existing plants and new construction both present significant (although somewhat different) challenges that make construction difficult and costly. With regard to working on an existing plant, from a design perspective, we had to work with the facilities that were already in place and design the new equipment to fit in the existing spaces and to work with other existing equipment. In new construction projects, while you have much

[28] Crisp Direct at 16:20-17:2.

more design freedom and are able to design spaces and other equipment to fit your needs, you must also contend with the costs and difficulties of complying with all of the requirements of construction in the nuclear environment.

Mr. Crisp states that proper planning includes confirming that the design is fully functional and can be physically built.[29] On this point I agree with Mr. Crisp. Mr. Crisp, however, did not provide any examples from Monticello where designs could not be constructed and acknowledged, in the Department's response to Company Information Request No. 7, that he had no such examples to provide. A copy of this response is included here as Exhibit ___ (TJO-2), Schedule 15.

I note that, while Mr. Crisp had no example to offer, the Company faced this situation. As I described in my Direct Testimony, we rejected design drawings that were not up to our standards and undertook additional design to improve constructability.[30] We had an instance where we rejected a design because we concluded it was not fully functional and we would have real problems actually constructing it. In that instance we prudently brought in an alternative designer to come up with a more feasible design. Far from being imprudent, our approach saved us several million dollars by not proceeding with suboptimal designs.

[29] Crisp Direct at 16:15-16.
[30] O'Connor Direct at 76 and 125-26.

Q. ARE YOU SUGGESTING THAT NEW CONSTRUCTION IN THE NUCLEAR INDUSTRY IS EASY BY CONTRAST?

A. Not at all. New construction of nuclear power plants has significant challenges of its own. For example, new nuclear construction projects have experienced significant cost increases well above initial estimates.

Q. DO GREENFIELD CONSTRUCTION PROJECTS EXPERIENCE COST HIGHER COSTS?

A. I have included a chart with my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 16, that provides costs and timelines for several greenfield nuclear construction projects. This Schedule provides comparisons of the estimated and actual costs of new construction BWRs and PWRs brought online between 1983 to the present. The Schedule also includes units anticipated to be placed in-service by 2020. As illustrated in this Schedule, costs for greenfield construction of nuclear facilities can exceed four to six times initial estimates.

c. Reasonably-Foreseeable Starting Point

Q. THE DEPARTMENT, THROUGH MS. CAMPBELL, CRITICIZES THE COMPANY FOR ITS INITIAL COST ESTIMATE OF $346 MILLION USED IN THE CERTIFICATE OF NEED APPLICATION FOR THIS INITIATIVE.[31] DO YOU AGREE THAT THIS WAS AN UNREASONABLE CERTIFICATE OF NEED-LEVEL ESTIMATE?

A. No. Based on the information we had at the time and the need to move promptly to capture the benefits for our customers during a period of high demand growth and high energy costs, that estimate was reasonable. I note that this $346 million estimate was adjusted for inflation and includes an allowance for the steam dryer (about $28 million).

[31] Campbell Direct at 22-27.

Q. DO YOU THINK THE COMPANY COULD HAVE DEVELOPED A MORE ACCURATE ESTIMATE IF IT HAD SPENT MORE TIME ON THE FRONT END DEVELOPING A MORE DETAILED INITIAL SCOPE?

A. Perhaps, but in simple terms, the Company had already more than doubled the estimates associated with prior uprates because it understood the scope of the LCM work at a plant with virtually no recent upgrades would be substantial. The $320-346 million estimate was a high-level and good-faith estimate of the overall cost to complete the complex LCM/EPU Program, as discussed in the Company's response to the Department's Information Request Nos. 51 and 53 attached here as Exhibit ___ (TJO-2), Schedule 17. Detailed engineering was subsequently completed through an iterative process as the modifications were developed and implemented throughout the duration of the Program. Nevertheless, I would agree that our initial estimate was low given the benefit of hindsight.

Q. WHAT OTHER COST LEVEL COULD THE COMPANY HAVE REASONABLY PREDICTED WHEN IT FILED FOR THE EPU CERTIFICATE OF NEED IN 2008?

A. Mr. Crisp appears to assume we should have used the $299-$362.5 million suggested in a 2011 memo that he discusses on pages 24-28 of his Direct Testimony ("2011 Cost History"). I do not agree with Mr. Crisp that an after-the-fact summary of options appropriately captures what amount the Company should have adopted in 2008, but I do acknowledge that this estimate was ultimately marginally closer than what the Company used.

If one takes the $299-$362.5 million, and adds an allowance for the steam dryer (about $28 million) and an adjustment for inflation, the comparable total to the $346 million estimate is in the range of $360 million to about $420 million. It is somewhat higher than our Certificate of Need estimate. I note that an initial estimate of about $420 million would not have changed the cost-effectiveness of the overall Program as discerned in 2008. If the Commission does not believe we appropriately captured reasonable cost projections based on information we knew at the time, this $360 million to about $420 million serves as an upper bound of that reasonably foreseeable initial cost estimate. And while this range is still far short of what we actually needed to spend to bring value to our customers, it reflects another way to look at the numbers.

Q. DO YOU BELIEVE THE COMPANY COULD HAVE DEVELOPED AN INITIAL ESTIMATE OF THE ACTUAL $665 MILLION (WITHOUT AFUDC) INCURRED?

A. No. Even in December 2011, after two outages we estimated Program costs of $587 million. At the time, there would have been no basis to conclude that the Program would cost $665 million. Many of the items that drove up our costs could not reasonably have been completely uncovered by advance planning. We could not have accurately predicted the challenges we faced with the productivity of craft labor.

Q. WHAT ESTIMATE SHOULD THE COMMISSION USE WHEN CONSIDERING THE COMPANY'S PERFORMANCE IN THIS CASE?

A. I believe the $346 million estimate was reasonable and supported by the facts as we knew them in 2006-08. However, if the Commission wants to consider a different starting point for purposes of measuring our performance or the cost-effectiveness of the initiative and avoid a pure hindsight analysis, I believe that the highest reasonable estimate is no higher than about $420 million. Such an estimate would account on the front end for the steam dryer and the effects of inflation. It is not reasonable to suggest we could have foreseen the starting point would exceed this range at the time.

Q. IF THE COMPANY HAD FORESEEN A HIGHER STARTING POINT, DO YOU THINK IT WOULD HAVE CHANGED ANY OF THE COMPANY'S DECISIONS OR ACTIONS?

A. No. As Department witness Mr. Shaw acknowledges, even if the final Program costs of $665 million were known during the Certificate of Need proceeding in 2008, that the Program would have been found to be "overwhelmingly cost-effective as a whole."[32] And at our split of 41.6 percent to EPU, the EPU alone is cost-effective.

d. Installation and Craft Labor

Q. DEPARTMENT WITNESS MR. CRISP CRITICIZES THE COMPANY FOR NOT ANTICIPATING THE DIFFICULTY AND THE COST OF CONSTRUCTION IN THE SMALL FOOTPRINT OF MONTICELLO.[33] HOW DO YOU RESPOND?

A. We anticipated a lot of this difficulty for construction and installation, as described by my Direct Testimony.[34] During the engineering and design phase for each of our modifications, we identified the areas that would be space-constrained and/or located in high-dose environments. For these areas, we worked with our implementation vendors and craft laborers to estimate the number of man-hours necessary to complete the requisite work. We relied on their expertise and input as well as the experience of our engineering staff to develop the work packages for each modification. Although we considered that certain inefficiencies would be encountered because of the small spaces or high-dose environments, even using the expertise of our implementation

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32 Shaw Direct at 14:1-2.
33 Crisp Direct at 18:30-19:11.
34 O'Connor Direct at 33 and 81.

vendors did not provide us with the information necessary to fully appreciate how long the work would take.

Q. MR. CRISP POINTS OUT THAT THE OVERALL INSTALLATION COST OF $290 MILLION IS TEN TIMES HIGHER THAN THE ORIGINALLY ESTIMATED $27.5 MILLION ESTIMATE REFERENCED IN YOUR DIRECT TESTIMONY.[35] HOW DO YOU RESPOND?

A. The $27.5 million was only General Electric's portion of installation costs. As we explained in our response to the Department's Information Request No. 37, our overall estimate included a significant amount of non-segregated common costs, including installation costs. I have included a copy of the Company response to the Department's Information Request No. 37 here as Exhibit ___ (TJO-2), Schedule 18.

Q. WHO WERE YOUR PRIMARY VENDORS FOR INSTALLATION?

A. Our primary vendors for installation were Day Zimmerman during the 2009 and 2011 outage and Bechtel (with Day Zimmerman as lead mechanical subcontractor) during the 2013 outage.

Q. WERE THE AMOUNTS PAID TO DAY ZIMMERMAN AND BECHTEL FOR THE PROGRAM PRIMARILY FOR CRAFT LABOR OR PROJECT MANAGEMENT?

A. I estimate that approximately 90 percent of the amounts we paid to Day Zimmerman for the 2009 and 2011 outages were for craft labor expenses. I estimate that approximately 75 percent of the amounts we paid to Bechtel for the 2013 outage were for craft labor expenses. We were able to complete a great deal of work during the Program because of these vendors' craft labor.

[35] Crisp Direct at 16:2-3.

Q. MR. CRISP ATTRIBUTES SOME OF THE COSTS TO POOR PLANNING AND THAT MONTICELLO SHOULD HAVE "KNOWN ABOUT THE PHYSICAL ARRANGEMENT INSIDE THE POWER BLOCK" BECAUSE "PLANT OPERATING PERSONNEL WERE REQUIRED TO INSPECT ALL SECTIONS OF THE PLANT" DURING OUTAGES.[36] DO YOU AGREE WITH THIS ASSESSMENT?

A. No. While it is true that Plant personnel complete scheduled inspections during outages, it is to verify the safe operation of Monticello. These inspections are not used to verify or create as-built drawings. Although there were outages that occurred after the initiation of the Program and before implementation began, outages are consistently time-constrained. Even before initiation of the Program, when Monticello was only undertaking LCM work during outages, the outage schedules would sometimes get extended. The estimated versus actual times for 2000 through 2007 are summarized in Table 4.

Table 4. Pre-Program Outages

Outage Year	Estimated Duration	Actual Duration
2000	47 days	54.7 days
2001	38 days	42 days
2003	25 days	30 days
2005	38.7 days	38.9 days
2007	45 days	45.8 days

The Company provided the actual duration of these outages in our response to the Department's Information Request No. 106, attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 19. Nuclear plants must return

[36] Crisp Direct at 17:16-21

to operation as soon as possible after an outage as they are a critical baseload resource as identified by Company witness Mr. James R. Alders in his Rebuttal Testimony. As soon as all work orders have been addressed and equipment has been appropriately pre-operationally tested, the baseload plants are brought back online. There is limited time to perform additional elective work during an outage beyond what is required for the continued operation of a plant.

2. Outage Timing Was Appropriate

Q. MR. CRISP RELIES ON THE 2011 COST HISTORY DOCUMENT TO SUGGEST THAT THE BOARD'S APPROVAL OF A 2009 AND 2011 IMPLEMENTATION FOR THE PROGRAM WAS IN DIRECT CONFLICT WITH THE SITE PROJECT TEAM RECOMMENDATION AND PROVIDED MONTICELLO WITH NO OPPORTUNITY TO CATCH UP TO THE WORKLOAD. HOW DO YOU RESPOND?

A. While the 2011 Cost History reflects that the site project team recommended a 2011 and 2013 implementation, the Nuclear Program leadership ultimately proposed a 2009 and 2011 implementation to meet the electricity demand needs of our customers. This apparent "disagreement" merely shows the normal give and take that occurs in corporations. The Company had competing priorities that needed to be addressed based on information gathered by the Resource Planning and Regulatory functions. Ultimately, it was good that we started implementation in 2009 as it required three outages to complete all the work required for the Program.

Q. WOULD MONTICELLO HAVE NEEDED TO PURSUE PARALLEL LICENSING, REGULATORY APPROVALS, ENGINEERING, AND INSTALLATION IF 2011 AND 2013 HAD BEEN APPROVED FOR PROGRAM IMPLEMENTATION?

A. Yes. To initiate construction by 2011, the Company would have still needed to multi-track its approach to the Program because of the timing of the Certificate of Need approval from the Commission. Without having started design in the early years, while we were also seeking regulatory approvals and working on licensing, we would not have been prepared for a 2011 outage.

Q. WHAT WOULD HAVE BEEN THE LIKELY SCHEDULE HAD THE COMPANY ELECTED TO MULTI-TRACK PREPARATIONS FOR A 2011 OUTAGE?

A. If we had selected to pursue implementation of the Program in 2011 and 2013 instead of 2009 and 2011, the work we completed in 2009 would have been pushed to the 2011 outage. The 2011 outage, as we implemented it, already had a substantial scope and adding all the work completed in 2009 to the 2011 outage would have likely created additional planning concerns. It is likely that this volume of work would have actually pushed us to three outages, just implementing them in 2011, 2013, and 2015. This would not have provided us with the benefit we currently have which is that the work at the Plant was completed at the time the License Amendment Request was received by the NRC. Additionally, this would have put us far later than the need identified in our resource planning process.

Knowing now how the overall implementation proceeded through 2013, the decision to begin implementation in 2009 was appropriate for our customers' interest. We provided the Department this information in the Company's response to the Department's Information Request No. 41 attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 20.

3. Design Preparation

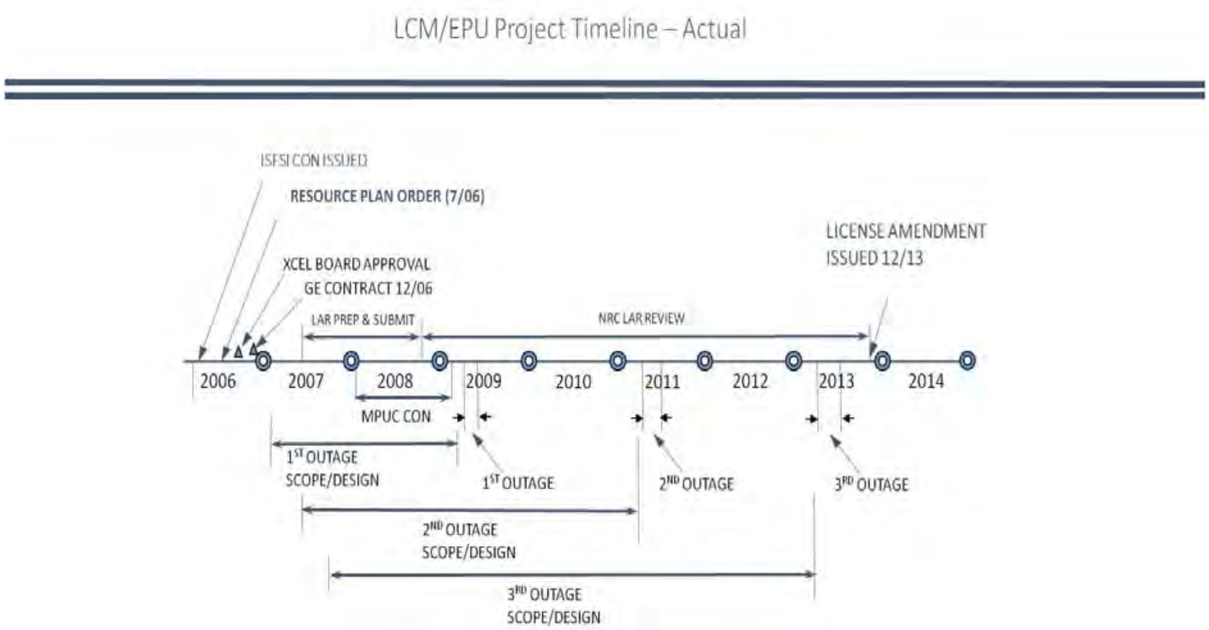
Q. MR. CRISP ALSO CRITICIZES THE COMPANY FOR HAVING PROCEEDED BASED ON "HIGH LEVEL CONCEPTUAL" DESIGNS.[37] HOW DO YOU RESPOND?

A. It appears that Mr. Crisp concludes that we should have undertaken a much more detailed design and engineering analysis prior to commencing work.

Q. CAN YOU GRAPHICALLY DEPICT THE IMPLICATIONS OF FOLLOWING THE APPROACH SUGGESTED BY MR. CRISP?

A. Yes. I first illustrate the approach the Company undertook and then contrast that to the approach Mr. Crisp suggested. The following Figure 1 is a timeline that shows a high-level view of the process that we undertook.

Figure 1. Actual Project Timeline



[37] Crisp Direct at 10.

Q. HOW MUCH MONEY WAS SPENT PREPARING FOR THE LCM/EPU PROGRAM FROM MID-2006 THROUGH THE APPROVAL OF THE CERTIFICATE OF NEED?

A. From the time the Company launched the integrated LCM/EPU Program in mid-2006 through obtaining the Certificate of Need in February 2009, Xcel Energy spent approximately $97 million on the combined LCM/EPU Program.[38] This included about $60 million in progress payments to General Electric, mainly for engineering and design work for the 2009 modifications. We also spent significant amounts to obtain long-lead-time items, such as a firm order on a block of steel needed to fabricate the new turbine. Our records show that we estimated we needed to place the order 30 months in advance to preserve our place in the queue. The payments to General Electric also allowed for reservation of equipment and materials in anticipation of the 2009 outage. This $97 million allowed us to make the best use of the 2009 outage and install associated modifications a mere two months after receiving the Certificate of Need in February 2009.

Q. IF THE COMPANY HAD UNDERTAKEN THE PREPARATION SUGGESTED BY MR. CRISP, HOW WOULD THIS HAVE CHANGED THE SCHEDULE FOR THE PROGRAM?

A. Figure 2 illustrates, in my opinion, what would have happened to the schedule if we had undertaken the type and level of preparation suggested by Mr. Crisp.

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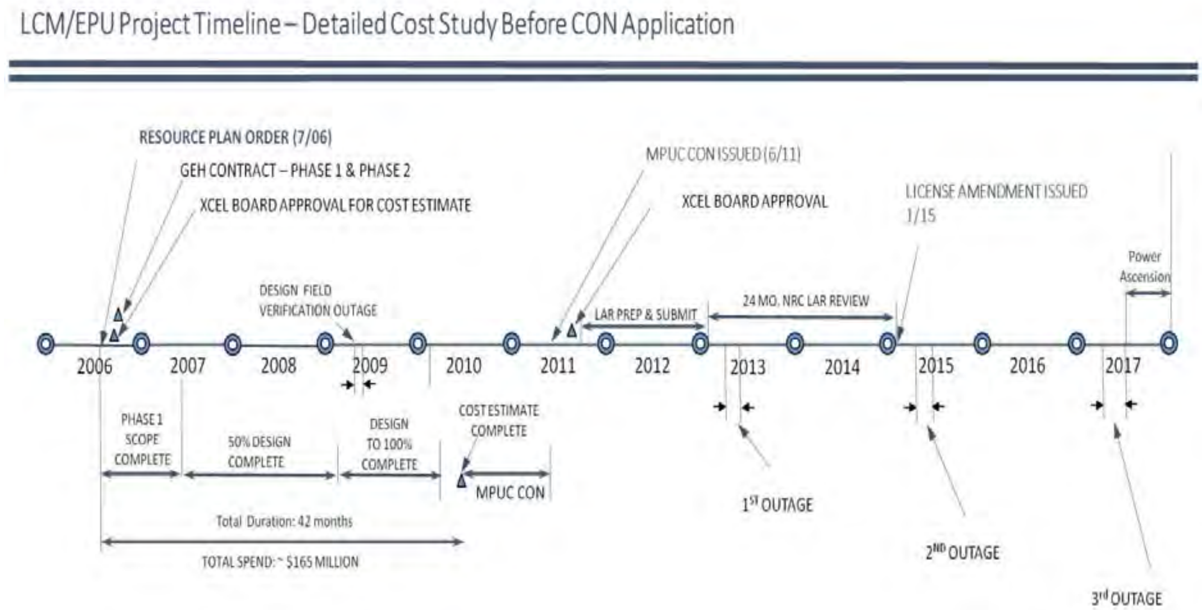
[38] *See* O'Connor Direct at 27, Table 4.

Figure 2. Engineering Estimates Before Certificate of Need Application



Q. WHAT IS FIGURE 2 BASED ON?

A. I interpret Mr. Crisp's testimony as essentially recommending that we should have undertaken at least a 60 percent design review[39] level as part of setting the initial scope. In my Direct Testimony, I discussed the general design process we undertook for the Program, and the internal oversight we provided for the design effort.[40] The Company provided more detail on what is involved in this effort and how time-intensive it is for a large undertaking like the Program in response to the Department's Information Request No. 19, which I have attached here as Exhibit ___ (TJO-2), Schedule 21.

To provide further detail on the level of design work that would be necessary to accomplish the design target identified by Mr. Crisp, I asked my design team to prepare a White Paper, which I have attached to my Rebuttal

[39] Our design process involves a 30/60/90 percent development and review.

[40] O'Connor Direct at 66:3-25.

Testimony as Exhibit ___ (TJO-2), Schedule 22. This White Paper explains the design development and review process, and provides a more detailed description of what is necessary to achieve the design target identified by Mr. Crisp. I used this information to evaluate the effort and time to do that level of activity on the front end of the initiative.

Q. ISN'T IT TRUE, HOWEVER, THAT IF YOU HAD UNDERTAKEN THAT LEVEL OF REVIEW, THE INITIATIVE WOULD HAVE COST LESS?

A. I seriously doubt it. Even at the 60 percent level of design, we would not have been able to fully account for as-found conditions and for hidden interferences and things like degraded wiring that were discovered during the actual installations. I think even if the Company had scoped the job "better" as Mr. Crisp says, we would still have encountered significant cost increases during installation, only the installations would have been much later. And some of the old equipment (*e.g.*, transformers, generator, pumps) may well not have lasted that long.

Q. DOES THE DEPARTMENT'S DIRECT TESTIMONY PROVIDE CONSISTENT CRITICISM ON YOUR LEVEL OF DESIGN WORK?

A. No. While Mr. Crisp is clear in his criticism that we did not do enough to prepare, I understood Mr. Shaw's Direct Testimony to criticize the expenditure of funds prior to the Certificate of Need.[41] Mr. Shaw suggested that there was a perverse incentive "for utilities to spend as much capital as possible early on since spending as much money as possible upfront would ensure that any remaining capital to be spent could be shown to be cost-

[41] Shaw Direct at 19:18-20:3.

effective[.]"[42] I take this to mean we should have waited to get the Certificate of Need before spending significant money in furtherance of the Program.

Q. DID THE NOTION OF SPENDING MONEY QUICKLY TO AVOID A COST-EFFECTIVENESS TEST EVER CROSS YOUR MIND?

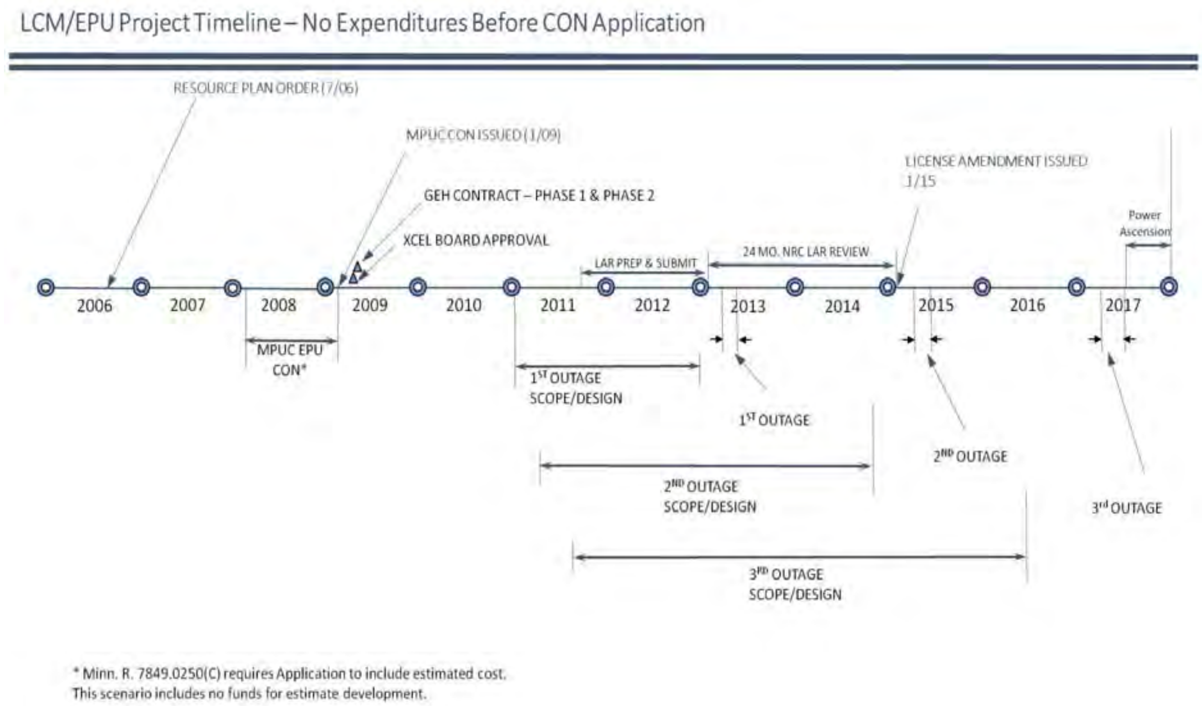
A. No. I was the Site Vice President in 2008. My primary focus at that time was to manage the Project well. In implementing the Program, we were not asked to, and did not, spend money early or without a clear purpose.

Q. WHAT IS FIGURE 3?

A. Figure 3 is a project timeline that illustrates, in my opinion, what would have happened to the schedule if the Company expended minimal money on the LCM/EPU Program prior to receiving the Certificate of Need. If the Company has not begun expending capital before receiving the Certificate of Need, Figure 3 illustrates the work would not have been completed until 2017.

[42] Shaw Direct at 19:20-22.

Figure 3. No Project Spend Before Certificate of Need Granted



Q. PLEASE EXPLAIN THE INCONSISTENCY BETWEEN MR. SHAW AND MR. CRISP.

A. Mr. Shaw implies the Company should not have spent money before receiving the Certificate of Need. Mr. Crisp effectively states the Company should have spent more money upfront than it did. Both paths, inconsistent as they are, lead to the same outcome – implementation would have been delayed by perhaps four years under either scenario.

Aside from the Company's need to add baseload capacity referenced in Mr. Alder's Direct and Rebuttal Testimonies, Monticello could simply not wait an additional four years. I am concerned the feedwater heaters, condensate demineralizers, and the generator could not have lasted an additional four years. The Commission should consider the condition of our facility at the time the Program was initiated when considering alternative timing scenarios.

B. Implementation

1. Necessary Scope Changes

Q. DEPARTMENT WITNESSES DR. JACOBS AND MR. CRISP TAKE ISSUE WITH THE "SCOPE CHANGES" THAT WERE MADE THROUGHOUT THE LCM/EPU PROJECT AND ALLEGE THAT THESE "SCOPE CHANGES" EVIDENCE POOR PLANNING ON THE PART OF THE COMPANY. DO YOU AGREE WITH THIS CHARACTERIZATION?

A. I want to clarify that the overall scope of our Program never changed. From the initiation of the Program in 2006, we intended to undertake the work necessary to allow the continued safe and reliable operation of Monticello to at least 2030 and that would address all pinch points identified for 120 percent operation required for the uprate.

We clarified the activities needed for each modification, and by the end of 2007, all major tasks for the Program were included. There were subsequent minor adjustments that did add materially to our costs but they were hardly imprudent. These included changes such as replacing degraded wiring when it was found with the condensate demineralizer system.

Q. HOW DID THE COMPANY GO ABOUT DETERMINING THE WORK FOR EACH MODIFICATION IN THE EARLY YEARS OF THE PROGRAM?

A. We developed engineering teams with a responsible engineer for each modification. Each team evaluated its modification and determined whether all the work necessary to implement that modification had been identified. Where a team identified that additional work would be required, the team modified the plan to include that work.

Q. WHEN WERE THE ACTIVITIES FOR THE MAJOR MODIFICATIONS IDENTIFIED?

A. The major modifications were identified largely in 2006 when General Electric provided the Scoping Assessment, refined in 2007 and set through 2008. After the final scope had been defined in 2008, the following major modifications required no revisions to the overall scope: turbine, steam dryer, PRNM System, and main and 1AR transformers.

Q, WHAT MAJOR MODIFICATIONS REQUIRED POST-2008 CHANGES TO THE SCOPE?

A. After 2008, we made revisions to the scope of work for the feedwater heaters, condensate demineralizer, reactor feed pumps and motors, condensate pumps and motors, and 13.8 kV electrical distribution system modifications. I have summarized these changes below:

- **Feedwater Heaters**
  - In 2009, initial analysis indicated that reinforcements to the turbine floor would be necessary to accommodate the increased feedwater heater weight. We explored options and chose a solution.
  - In 2012, we identified a need to install vents, drains, and flashing for the 14A/B and 15A/B feedwater heaters.
  - We identified modifications to drain cooler penetration locations, and design of safety supports for installation due to interferences.
- **Condensate Demineralizer**
  - Removal of interferences during the 2011 outage that were not identifiable prior to disassembly of existing tanks and vaults.
  - T-33 backwash receiving tank and air surge tanks required in-outage design and modification in 2011.
  - Existing wiring was not available for inspection prior to the 2011 outage. Once accessible, the condition necessitated replacement.

- **Condensate Pumps and Motors**
  - In 2009, we determined the NPSH required for the pumps was higher than what was available. We increased the hotwell level by 0.5 feet to address this.
  - To accommodate the designs, our motor designer had to add sufficient iron to the motor stator to accommodate our pre-defined startup requirements. Once this iron was added, we determined in 2011, that the heat produced would require modifications to the condensate room HVAC system.
- **Reactor Feed Pumps and Motors**
  - In 2009, we learned that the new pumps and motors contained monitoring equipment that required modifications to our current system inputs.
- **13.8 kV Electrical Distribution System**
  - In 2009, we identified the final location for the 13.8 kV switchgear room and designed the necessary cabling and tray designs. This location required that we relocate the Monticello hot shop.
  - In 2012, our initial transport and heavy haul path analysis concluded that no matting would be necessary. The final analysis, however, in 2013, determined that matting would be required and this was added to the scope of work for the 13.8 kV modification.

Q. WERE THESE CHANGES REASONABLE AND PRUDENT?

A. Yes. The changes that we made to the modifications were necessary to the long-term health of Monticello and are not indications of imprudent project management.

2. Management Decisions to Minimize Costs

Q. MR. CRISP MAKES GENERAL STATEMENTS THAT PROJECT MANAGEMENT ISSUES RESULTED IN COST OVERRUNS. CAN YOU COMMENT?

A. Yes. Mr. Crisp generally describes a project that seemed relatively unconcerned about costs incurred. His description does not accurately reflect how we approached this job. We actively managed our resources, particularly the work done by our design and implementation vendors, through our project management processes. In managing our resources, there were multiple occasions where we identified concerns with the work provided by a vendor and attempted to work through those issues with the vendor, but if we were unable to reach an agreeable resolution, we engaged one of our other qualified vendors that we had at our disposal. In many of these instances, we were able to save costs during the Program through this process.

Q. WHAT WERE SOME OF THE REASONS YOU USED ALTERNATE VENDORS FOR WORK DURING THE COURSE OF THE PROGRAM?

A. The reasons varied from quality of work product to cost to efficiencies. In some instances, we identified vendors that had a more specially-defined skill set than a vendor we initially intended to use for design work and we transferred the work to the alternate vendor to reduce a learning curve associated with our plant equipment or because of a successful experience we previously had with that vendor during the early stages of the Project. In other instances we identified and used alternate vendors to save costs during the course of the Program.

Q. DO YOU THINK THAT CHANGING DESIGN VENDORS DURING THE COURSE OF THE PROGRAM WAS MORE COSTLY OR IMPRUDENT ?

A. No. I do not. Where we changed design vendors, it was for a reasonable and defensible reason, whether it be cost, skill set, or quality of work product. As Department witness Mr. Crisp notes, "loss of faith in a contractor due to continued design or construction problems, or continued budget issues, or the failure to meet schedules are all real justification for removal of a contractor."[43] Prior to changing design vendors we evaluated our concerns against the potential ramifications for making that change. In the end, I believe that where we changed design vendors, those changes were appropriate decisions for the success of the Program.

Q. CAN YOU POINT OUT EXAMPLES OF WHERE THE COMPANY MADE PROJECT MANAGEMENT DECISIONS THAT REDUCED COSTS FOR THE PROGRAM?

A. Yes. I can point to several examples where the Company made prudent management decisions that resulted in cost savings. First, when we rewound the main generator in 2011, the Company cut a hole in the side of the turbine building and established a "contamination free" zone around the generator. This allowed all of the workers to enter/exit without going through the radiation monitoring and dosimetry stations each time they went to the job site which improved worker efficiency. It also allowed tooling and the generator itself to enter and exit without being monitored for contamination. This was a first for the station and saved several hundred thousand dollars.

Another example is the decision to construct a scaffold platform above the existing 4 kV equipment. Not only did this scaffolding protect the 4 kV

[43] Crisp Direct at 21:2-4.

equipment but it also allowed workers to install conduits and hangers in a very congested area prior to the 2013 outage. This work plan reduced the amount of work that had to be done during the outage itself.

Q. MR. CRISP CRITICIZES CHANGES IN PROJECT MANAGEMENT AND DESIGN VENDORS AS A "DISJOINTED PROCESS."[44] DO YOU AGREE?

A. No. As I discussed previously in my Rebuttal Testimony, I believe that where we made changes, those were appropriate decisions for the success of the Program. I do not believe this was a disjointed process. We made changes in design vendors where it was necessary to address issues with budget planning, work product, or meeting schedules. Mr. Crisp agrees that these reasons "are all very real justification for removal of a contractor."[45]

Q. YOU PROVIDED SOME EXAMPLES OF PROJECT MANAGEMENT CHANGES THAT SAVED THE PROJECT MONEY. ARE THERE EXAMPLES OF DESIGN CHANGES THAT CONTRADICT MR. CRISP'S ASSERTION THAT CHANGES DURING A PROJECT CONTRIBUTE TO INCREASES IN COSTS?

A. There are several. The most remarkable cost savings were for designs related to the reactor feed pumps and motors and condensate pumps and motors modifications.

Q. PLEASE DESCRIBE THE COST SAVINGS YOU WERE ABLE TO QUANTIFY FOR CHANGING DESIGN VENDORS FOR THE REACTOR FEED PUMPS AND MOTORS MODIFICATION.

A. The design originally presented required a substantial amount of extra work. This is an example of Mr. Crisp's statement that designs that appear fully

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[44] Crisp Direct at 20:7-9.

[45] Crisp Direct at 21:2-4.

functional on paper but cannot be physically built are not good.[46] In this instance, the original proposal required removing and rerouting over 290 feet of piping whereas our final design required removing and rerouting only 60 feet of piping. This removal and rerouting would have also required removal and reinstallation of insulation. Further, our final design vendor agreed to go with a lesser diameter pipe than the original design. This change reduced the welding time for the pipe by 15 percent. Our change in design saved approximately $6.6 million in installation costs.

Q. HOW DID THE PROGRAM SAVE MONEY BY CHANGING DESIGN FOR THE CONDENSATE PUMPS AND MOTORS MODIFICATION?

A. The Program saved approximately $2.2 million by changing design for the HVAC system design related to the condensate pumps and motors modification. To achieve the requisite motor design, the heat loads of the motors exceeded the cooling capability of the existing HVAC system for the condensate pumps and motors. The design proposed by our original designer was unacceptable and would have required the installation of glycol chillers.

C. Evolving Project Management was Appropriate

1. 2011 Cost History

Q. MR. CRISP REPEATEDLY CITES THE 2011 COST HISTORY TO SUPPORT INFERENCES REGARDING PROJECT MANAGEMENT AND COSTS. ARE YOU FAMILIAR WITH THIS DOCUMENT?

A. Yes, I am. The 2011 Cost History was written by an engineer at Monticello for the purpose of providing context and information to the CNO in 2011.

[46] Crisp Direct at 16:13-16.

Q. IS MR. CRISP'S USE OF THE 2011 COST HISTORY APPROPRIATE?

A. No. I understand that this single document forms the basis for most of Mr. Crisp's criticisms. This document was prepared by one employee based on documentation available to him. The Company's approach to the Program and its structure, especially as it relates to input from various business organizations in making Program decisions, is described in our response to the Department's Information Request Nos. 107 and 108, attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 23. Additionally, the author of the document was not personally aware of what information was presented by the Nuclear Projects Team to the Board of Directors or of the discussions that occurred after the Nuclear Projects Team received information from the site projects group.

The Company previously provided context for the 2011 Cost History in response to the Department's Information Request Nos. 77, 78, and 80. I have attached our responses to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 24.

Further, the 2011 Cost History was prepared at a time when the Program was under substantial pressure for missing cost and timing targets. During that period, tensions were running high and some attempts to assign blame naturally occurred. While it was easy to criticize the Program in 2011 as it had exceeded initial cost estimates, the author's own estimate that he believed should have been used was not substantially different than our own high sensitivity estimate in the Certificate of Need proceeding. Mr. Crisp does not acknowledge this information anywhere in the five pages of testimony he devotes to his analysis of the five-page 2011 Cost History.

Q. DO YOU AGREE WITH THE PROJECT MANAGEMENT AND BUDGETING CRITICISMS IN THE 2011 COST HISTORY?

A. The 2011 Cost History accurately reflects the author's perspective of the Program as it sat in late 2011. The 2011 Cost History is not, however, an accurate assessment of the Program, particularly the summaries provided on pages three through five. I specifically disagree with Mr. Crisp's conclusions that the budget for the Program was "decreased" and the Program timeline was "accelerated" by the Board of Directors. Mr. Crisp acknowledged in the Department's response to Company Information Request No. 9 that the 2011 Cost History was the only document he uses to support these conclusions. A copy of Mr. Crisp's response is included with my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 25.

My views of the project management, the increase in Program costs, and Program implementation are summarized in the Company's response to the Department's Information Request No. 48 an attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 26. In this response, we describe how the management of the LCM/EPU Program evolved appropriately over the course of the Program as it progressed through the study, design, and implementation phases and as the complexity of the job increased.

2. *Initial Project Management*

Q. ATTACHED TO MS. CAMPBELL'S TESTIMONY IS A NOVEMBER 14, 2013 ARTICLE FROM THE STAR TRIBUNE THAT SUGGESTS THAT PROJECT MANAGEMENT ISSUES CONTRIBUTED TO THE HIGHER PROGRAM COSTS, IN PARTICULAR THAT THE MANAGEMENT CHANGES IMPOSED AFTER THE 2011 OUTAGE WERE IMPOSED TOO LATE TO CURB COST INCREASES. HOW DO YOU RESPOND?

A. The Company's project management practices before or after 2011 did not materially contribute to the costs incurred. We established project management practices appropriate to the circumstances we encountered. As the complexity of the job increased, we adapted our practices to address those evolving circumstances. In the end, all of the costs that were incurred were necessary and reasonable to achieve the desired outcome.

Q. DESCRIBE THE COMPANY'S INITIAL PROJECT MANAGEMENT PLAN TO IMPLEMENT THE LCM/EPU PROGRAM.

A. We established a series of core principles that guided implementation. Many of these controls around engineering and quality worked well. Our project controls were consistent with other projects within the nuclear department.

- Our vendors contracts include an orderly process for change orders.
- We require vendors to develop and implement recovery plans to overcome performance issues that arise during implementation.
- We implemented rigorous QA/QC procedures to ensure quality.
- We employed an internal project manager to led the Company's LCM/EPU team and to oversee our key vendors, General Electric (design/engineering) and Day Zimmerman (initial installations).

Q. WHY DID THE COMPANY CHANGE ITS PROJECT MANAGEMENT APPROACH AFTER THE 2011 OUTAGE?

A. Our concerns arising from the 2011 outage were only in part about outage duration and cost. We were also concerned with the level of resource commitment from other Plant personnel that was required to achieve this result. Further, we were concerned about the adequacy of internal estimates of our overall Project costs. With respect to our first concern, in 2011, we found our personnel were required to fill some gaps that took them away from their other work. The difficulties we encountered in 2011 suggested that the remaining work for final implementation would be significant and that it was not sustainable to rely as heavily on internal resources.

Q. WHY DID THE COMPANY NOT MAKE THESE PROJECT MANAGEMENT CHANGES AFTER THE 2009 OUTAGE?

A. After the 2009 outage we assessed our performance and concluded that our project management practices remained appropriate. We received reasonably good performance and productivity. The installation of modifications in 2009 ran on schedule for the first 75 percent of the outage but lagged slightly over the remainder of the outage. Further, we experienced approximately $9 million of implementation costs over our budgeted amount, but these excess costs were primarily related to the need for additional labor and materials over what we had initially allotted. We gained valuable experience from the 2009 outage and concluded that the team's performance was such that it justified retaining the same team for the 2011 outage.

Q. WHEN DID ISSUES BECOME MORE APPARENT?

A. After the 2009 outage, we were on track for designs and work packages for the 2011 outage. Despite this early planning, we had to reject all engineering packages presented in 2010. At this time our vendors encountered a shortage of workers and experienced nuclear laborers and had a high turnover rate, as did the entire nuclear industry. Because of these issues, we worked closely with them to recover from missed deliverables and deadlines. We actively managed the challenges that were presented to us and developed recovery plans to prepare for the upcoming 2011 outage.

3. Transition of Implementation Vendors

Q. MR. CRISP TESTIFIES THAT CONTINUED CHALLENGES WITH A VENDOR CAN PROVIDE JUSTIFICATION FOR REMOVAL OF A VENDOR.[47] WHY DID THE COMPANY NOT RETAIN A NEW VENDOR FOR THE 2011 OUTAGE?

A. As I have testified, the 2009 outage went reasonably well. We were somewhat concerned about employee turnover but recognized that this was fairly common to the nuclear industry. We discussed this with our vendor and they assured us that it had the bench strength to complete the requisite work in preparation for the 2011 outage and through the outage. As a result we made the choice to stay the course.

Q. WHAT WERE THE COSTS OF THESE ISSUES DURING THE 2011 OUTAGE?

A. The combination of these planning and preparation issues impacted our ability to complete engineering packages well ahead of the 2011 outage to complete pre-outage preparations, as we had initially planned. These issues carried over into the outage and I was disappointed by the difficulties we encountered. We

[47] Crisp Direct at 21:2-4.

anticipated to spend $101 million over 65 days and instead ended up with costs of $135 million over 81 days. Looking back at the dollars spent by our installer to prepare for the outage, we are able to further evaluate the cost of installation during the outage.

Table 5. 2011 Outage Costs

2013 Outage	Duration	Costs Incurred
Planned	65 days	$101 million
Actual	81 days	$135 million
Ratio of Actual to Planned	1.25 days	1.34

Q. WHEN DID THE COMPANY RETAIN BECHTEL?

A. In late 2010.

Q. WHY DID THE COMPANY RETAIN BECHTEL?

A. Initially, we retained Bechtel to assist us with general nuclear projects. We identified Bechtel as a quality engineering house with a global reach, sufficient resources, and nuclear depth to help us on big jobs. There was a trend of less experienced or new nuclear craft labor during our Program. In 2009, I estimate that 90 percent of our craft supervision and labor were nuclear-experienced. In 2011, I would estimate that number declined to 45 percent. This and the complexity to finish the remaining aspects of the Program necessitated changes for the 2013 outage.

Early in 2011 we began discussions with Bechtel to determine if they had the capacity to assist us with the final stages of the LCM/EPU Program at Monticello. When the 2011 outage concluded, we decided to bring Bechtel in as our primary contractor because of its greater depth and experience. We also retained Day Zimmerman as Bechtel's main mechanical subcontractor to retain institutional knowledge and preserve continuity.

We made other project management changes leading up to the 2013 outage that are outlined in my Direct Testimony and will not be repeated here.[48]

Q. MR. CRISP CAUTIONS THAT WHEN VENDORS ARE CHANGED DURING THE COURSE OF A PROJECT, LIKE THE DECISION TO RETAIN BECHTEL IN 2011, COSTS INCREASE.[49] DO YOU AGREE WITH THIS?

A. Not necessarily. Changes during a project can also reduce costs from what they would otherwise have been as illustrated by the examples I previously discussed where we changed design vendors. We believe that changing vendors before the 2013 outage was appropriate because we were anticipating an outage in 2013 that would require even more challenging work than we had undertaken in the 2009 and 2011 outages.

Q. DID THE COMPANY'S CHANGES TO PROJECT MANAGEMENT AFTER THE 2011 OUTAGE REDUCE COSTS?

A. Our adoption of a different approach to project management in 2011 did not avoid incurring costs. Indeed, our greatest cost increases occurred in the 2013 outage, despite having brought in additional internal and external resources for the final phase of the Program. The 2013 outage exceeded our initial estimate by roughly $52 million, as summarized in Table 6, higher than the expected cost from both the 2009 and 2011 outages combined.

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[48] O'Connor Direct at 83-87.

[49] Crisp Direct at 22:8-11.

Table 6. 2013 Outage Costs

2013 Outage	Duration	Costs Incurred
Planned	85 days	$99 million
Actual	138 days	$151 million
Ratio of Actual to Planned	1.62	1.53

Our more detailed planning and reporting helped provide more transparency on how and why costs were incurred; however, we could not keep costs from increasing since they were necessary for successful completion.

Q. WAS BECHTEL ABLE TO ESTIMATE ITS COSTS?

A. No. Despite Bechtel's obvious experience in this arena, their estimates also evolved as we prepared for the 2013 outage.

Q. WAS THE BECHTEL PERFORMANCE WORSE DUE TO ITS UNFAMILIARITY WITH THE PROGRAM AND THE PLANT?

A. No. Bechtel had two solid years to plan for the outage and sufficient time to develop detailed work packages and detailed implementation estimates. The reason for their difficulties was the challenge of the 13.8 kV installation.

4. *Self-Evaluations*

Q. DID MONTICELLO COMPLETE ANY PERIODIC EVALUATIONS OF PROJECT MANAGEMENT DURING THE PROGRAM?

A. Yes. After each of our Program outages, we developed lessons learned evaluations. These evaluations were critical to the improvements we made throughout the life of the Program and are a key part of continuous improvement encouraged in the nuclear industry.

Q. HOW DID MONTICELLO GO ABOUT DEVELOPING THE LESSONS LEARNED AFTER EACH OUTAGE?

A. After each outage, the project manager requested that the engineer responsible for an installed modification provide detailed feedback on that modification's lessons learned. To do this, each lead modification engineer was asked to develop a summary of modification successes or issues and what could be done to capitalize on that success for other modifications or address the issue to avoid its propagation elsewhere in the Program.

Q. DID THE LESSONS LEARNED EVALUATION PROCESS CONTINUE FOR 2013?

A. Yes. Although we have completed the Program, we continue to seek opportunities to improve outage and work package planning and implementation at Monticello. We underwent a lessons learned process after the 2013 outage and will continue to self-evaluate after future outages to identify operational improvements.

Q. IS IT COMMON TO IDENTIFY LESSONS LEARNED FOR OUTAGE ACTIVITIES?

A. Yes. It is consistent with Institute of Nuclear Power Operations ("INPO") principles to self-assess performance during outages to identify lessons learned. The nuclear safety culture calls upon nuclear utilities to strive to learn from and improve its processes. Development of lessons learned for our own actions is not evidence of imprudence, but is a portion of industry-standard project management principles.

D. Measurement of Mr. Crisp's Criticisms

Q. DOES MR. CRISP PROVIDE ANY QUANTIFICATION OF COSTS ASSOCIATED WITH HIS ALLEGATION OF POOR PLANNING OR MANAGEMENT BY THE COMPANY?[50]

A. He does not.

Q. DID YOU ATTEMPT TO QUANTIFY THESE COSTS?

A. Yes. I directed my staff to work with Company consultants to try to determine: (1) if the 2011 outage implementation showed signs of uncontrolled spending; (2) if there were any excess costs arising out of field design changes that arose from difficult installation conditions based on Mr. Crisp's assertion that the Company was inadequately prepared for the installations; (3) a ceiling on a potential amount of cost savings had the Company not moved some design work among vendors during the Program thereby eliminating potentially duplicative design work; and (4) to quantify the amount of work that was unusable because of scope changes, changes in NRC requirements, changes in design, or other reasons.

1. Outage Efficiency Analysis

Q. DID YOU UNDERTAKE AN ANALYSIS TO COMPARE THE OVERALL EFFICIENCY OF THE 2011 OUTAGE COMPARED TO THE 2013 OUTAGE?

A. Yes. The 2011 outage was hard and has become the focus of some of the Department's criticisms. I considered the question of whether we could determine if the "burn rate" for the 2011 outage shows out of control spending.

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[50] Crisp Direct at 28.

Q. WHAT DID YOU DO?

A. I reviewed the amount we spent in preparation for the 2011 outage plus the amount spent in the outage and compared that with the comparable inputs for the 2013 outage.

Q. PLEASE DESCRIBE YOUR PROCESS.

A. For the 2011 outage, I added the amount we spent in the six months leading up to the outage (as a proxy for outage preparation costs) to the costs incurred during the outage to come up with an aggregate daily "burn rate" of $0.91 million/outage day for preparation and actual installation work. I made a similar calculation for the 2013 outage was $0.91 million/day. This comparison illustrates that our adjusted per outage day costs were about the same for the 2011 outage to the 2013 outage. Table 7 illustrates the comparison.

Table 7. Comparison of the 2011 and 2013 Outage Costs

	2011 Outage	**2013 Outage**
Outage Planning	$10.7 million	$32 million
Outage Costs	$135 million	$151 million
Actual Outage Days	87	138
Estimated cost per Outage Day	$0.91 million	$0.91 million

The results confirmed the work I saw took place. Bechtel spent substantially more time planning for the outage and managed their implementation costs downward but their efficiencies came with a cost. I think this illustrates that there were not costs that could be readily saved by differing approaches to Project implementation.

Q. WHY DO YOU NOT INCLUDE THE 2009 OUTAGE IN THIS ANALYSIS?

A. The 2009 outage was qualitatively and quantitatively quite different. In 2009, we focused on equipment replacements that did not include difficult system modifications and construction. Thus it would be a false comparison to include the 2009 outage in this analysis.

2. Field Change Orders

Q. PLEASE EXPLAIN YOUR ANALYSIS OF FIELD DESIGN CHANGES?

A. At most, we may have been able to save a nominal amount, less than $1 million if we had planned "better" as Mr. Crisp argues. The Company undertook a significant number of field changes during implementation. I conducted a review of the field changes to determine if I could detect any material costs that could have been avoided if, as Mr. Crisp asserts, the Company had been better prepared.

In the Company's response to the Department's Information Request No. 28, which I have attached as Exhibit ___ (TJO-2), Schedule 27, the LCM/EPU Program had numerous construction field changes, approximately 2,000 of which resulted from discrepancies in as-found conditions. To quantify a potential cost savings that may have resulted from earlier planning for what subsequently became the field changes I undertook a multi-step analysis.

Initially, I segregated the changes by the three groupings: basic field changes, intermediate field changes, and complex field changes. I then selected a sample of field changes, I reviewed each from the perspective of whether the particular field change could have been identified prior to the outage when it was discovered. This required segregating the samples into two categories, those that could have reasonably been identified pre-outage based on the level of planning and design Mr. Crisp suggests and those that could not. For those that could not, no further analysis would be required.

Further, for those field changes that reasonably could have been identified pre-outage, I attempted to determine if a different, less costly fix could have been developed before the outage. Based on the results of that analysis, I was able to estimate a potential cost savings from the sample analyzed.

Q. WAS THE EXISTENCE OF THE AMOUNT OF DISCREPANCIES BETWEEN THE DESIGNS AND THE AS-FOUND CONDITIONS UNUSUAL?

A. No. As explained in the Company's response to the Department's Information Request No. 27, attached as Exhibit ___ (TJO-2), Schedule 9, the Company was under no obligation to create as-built drawings for non-safety related systems although we agreed to record what we modified. Because we did very little major construction before the LCM/EPU Program, there were very few as-builts that had been completed for the Plant.

Q. IF THE COMPANY HAD FOLLOWED MR. CRISP'S APPROACH TO SCOPING AND DESIGN, PLEASE DISCUSS YOUR CONCLUSIONS ABOUT WHETHER THE COMPANY WOULD BEEN ABLE TO AVOID FIELD CHANGES AND ANY ASSOCIATED COST SAVING?

A. My conclusion is that the vast majority of field design changes could not have been avoided and that for the ones that could have been avoided, the Company would have realized only a modest cost savings.

Even at the level of design completion Mr. Crisp suggests, the types of issues we encountered that required us to undertake field changes would not have been known. For example, we encountered rebar interferences in thick concrete walls floors. Rebar is reinforcing steel that is embedded into concrete to strengthen it, which is not visible without the use of specialized equipment. While specialized equipment can detect its location within concrete, that is simply not performed at any level of design in my experience. Its location is typically discovered only as the construction work is performed.

In my analysis and engineering judgment, no more than five to ten percent of the field design changes we encountered could have been discovered had we completed the level of design completion Mr. Crisp suggests. Thus, even expending the effort to complete detailed designs earlier, I do not think it would have substantially reduced our installation costs. I summarize the costs associated with each category of field changes in the Table 8.

Table 8. Field Change Cost Categorization

Category of Change	Total Number	Sample Size Reviewed	Cost per Change	Total Associated Cost
Basic	Approx. 1,600	Approx. 5%	$1,000-$10,000	$8-13 million
Intermediate	Approx. 400	Approx. 5%	$10,000-$250,000	$12 million
Complex	2	2	$2 million and $3 million	$5 million

Both complex field changes are discussed in detail in the Company's response to the Department's Information Request No. 28, which I have attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 27.

While I do not believe the Company could have discovered the vast majority of work encompassed by the field design changes at the level of design completion Mr. Crisp suggests, I do believe for the small amount we could have discovered we would have realized some efficiency gains had we earlier discovered those field design changes. Therefore, I conclude the cost savings associated with Mr. Crisp's suggested path would have been nominal, definitely no more than $1 million.

3. Potentially Duplicative Design Costs

Q. WHAT DOES YOUR NEXT ANALYSIS ADDRESS?

A. Mr. Crisp made a number of general criticisms, that while characterized as project management criticisms, really implicate the Company's engineering and design process. More specifically, Mr. Crisp seemed to state that excess design work was performed based on his assertion that the Company replaced vendors and allegedly engaged in "starts and stops" during the design effort.[51] In particular, Mr. Crisp was critical about the evolving scope of the design effort. My second analysis quantifies the ceiling on a potential amount of cost savings had the Company not moved some design work among vendors during the Program. I disagree with the notion that the Company should not move design work among vendors and am providing this analysis in the event Mr. Crisp provides factual support that moving design work was imprudent, which I do not believe exists.

[51] Crisp Direct at 20:7-9.

Q. PLEASE EXPLAIN HOW YOU QUANTIFIED THE ADDITIONAL DESIGN COSTS.

A. As outlined in the Company's response to the Office of Attorney General's Information Request No. 6, attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 28, Xcel Energy incurred design costs from several design-related vendors.

First, I reviewed the Company documents to determine the scope of work performed by these vendors to determine if it was all design-related or not. As an example, some vendors provided planning personnel as additional outage resources. This is not design-related and all similar non-design-related costs were removed from the analysis. Second, I made a determination of whether the subsequent design-related work paid for by the Company was part of the original scope or not. The dollars associated with the work that was potentially part of the original design scope form the pool of potential dollars associated with Mr. Crisp's criticisms, as the dollars for the expanded scope would have resulted in a change order. Table 9 summarizes my review:

Table 9. Contract Releases

Other Designers	Number of Contract Releases Reviewed	Not Part of Initial Scope	Expansion of Initial Scope	Within Initial Scope
1	Approx. 140	$19,286,570	$0	$6,610,006
2	Approx. 130	$7,097,949	$0	$5,728,451
3	Approx. 40	$5,674,737	$1,808,992	$597,489
	TOTAL	$32,059,256	$1,808,992	**$12,935,946**

Q. PLEASE EXPLAIN THE CONCLUSIONS YOU DRAW FROM THIS ANALYSIS?

A. Approximately $13 million was at least arguably related to the scope of work in the initial contracts.

Q. SHOULD THE COMPANY'S RECOVERY BE LIMITED AS A RESULT OF THE THIS EVALUATION?

A. No. The results of this evaluation are not signs of imprudent action by Xcel Energy. I believe we were exercising good judgment in bringing in other vendors to complete work as efficiently as possible under the circumstances.

Q. HAS THE COMPANY BROUGHT ANY CLAIMS ASSOCIATED WITH THIS ISSUE?

A. We are working through a number of issues and have reached settlements on some potential claims. It is my understanding that the Company has committed to offset any claims or settlements it achieves to the cost of the Program so that ratepayers obtain the benefit of any such settlements.

4. Abandoned Work

Q. DISCUSS THE FOURTH MEASUREMENT UNDERTAKEN BY THE COMPANY.

A. The Company also identified work that was ultimately not fit for its intended purpose because of scope changes, changes in NRC requirements, changes in design, or other reasons. However, this work may have had other purposes or been a part of a necessary process to optimize the final design of LCM/EPU modifications. The Company quantified this work in response to an Information Request from the Office of the Attorney General during the 2012 rate case. I have attached a copy of the Company's response as Exhibit ___ (TJO-2), Schedule 29. This work totaled approximately $11 million.

VII. LCM/EPU COST SEPARATION ANALYSIS

A. Company's Analysis of LCM/EPU Costs

Q. IS IT APPROPRIATE TO SEGREGATE COSTS FOR THE PROGRAM BETWEEN LCM OR EPU?

A. No. The LCM/EPU Program was implemented as an integrated effort. As a result, we did not segregate costs between LCM and EPU components. The investments we made at Monticello are overwhelmingly cost-effective as a whole and I believe viewing the costs as a whole is the proper perspective.

I view all costs incurred as part of the LCM/EPU Program as integral to the uprate as well as Monticello's continued operation given that this work was necessary to allow safe and reliable operation of this Plant until 2030 and possibly beyond. If we had not made the necessary underlying investments to ensure the long-term operation of Monticello, we would not have been able to undertake uprate activities. As a result, the total investment in Monticello should be judged based on the overall value that was provided to the long-term operation of Monticello rather than making artificial distinctions between costs for the Project.

Q. THEN WHY DID THE COMPANY BREAK OUT LCM AND EPU COSTS OF THE PROGRAM IN THE 2008 CERTIFICATE OF NEED PROCEEDING?

A. As part of the 2008 proceeding, the Company performed a high-level conservative assignment of Program costs to either LCM and EPU for the purposes of comparing costs of the Program against other reasonable alternatives as required by Minnesota rules. This exercise resulted in apportionment of 58.4 percent of cost to LCM and 41.6 percent to EPU. This allocation was conducted solely for the 2008 Certificate of Need.

Q. WHAT WAS THE BASIS FOR THAT INITIAL LCM/EPU SPLIT USED FOR MODELING PURPOSES IN THE CERTIFICATE OF NEED?

A. Our Project team did an informal assessment of the modifications that were projected at the time and assessed a good faith, albeit rough, estimate of the costs that could be assigned to LCM and those to EPU. The team assessed the equipment and made an allocation based on reasonable engineering judgment.

Q. ARE YOU COMFORTABLE THAT THE SPLIT DEVELOPED IN THE CERTIFICATE OF NEED PROCEEDING WAS PREPARED IN GOOD FAITH BASED ON THE INFORMATION THE COMPANY HAD AVAILABLE AT THE TIME?

A. Yes. In his pre-filed testimony in the Certificate of Need proceeding, Company witness Mr. Allen Williams provided a discussion of some of the capital projects that he believed needed to be undertaken as part of the initiative.[52] He concluded that $104 million would be needed to support the EPU. This is about one-third of the initial costs. However, he describes that if the steam dryer needs to be replaced it would raise the EPU cost to $133 million. If one uses the adjusted $320 million starting point figure that was used at the time to reflect inclusion of the steam dryer, the EPU proportion is 41.6 percent. This is the split that was used in the modeling for the Certificate of Need.

[52] Williams Direct Testimony in Docket E002/CN-08-185 (June 6, 2008).

Q. DID THE COMPANY CONDUCT ANY ADDITIONAL ANALYSIS OF THIS LCM/EPU ALLOCATION?

A. Yes. As part of our initial filing in this Docket we examined the costs of the Program focusing on what costs could be avoided if we did not undertake the EPU. This was different than the analysis that we conducted for the Certificate of Need. We referred to this analysis as the "avoided cost" analysis. Under this analysis, we categorized the costs for specific modifications in one of three ways: (1) LCM-only costs: costs there were solely related to LCM activities; (2) EPU-only costs: costs that were solely related to EPU activities, including licensing costs; and (3) LCM costs that include some incremental EPU costs over and above what would have been needed absent the EPU.

Q. WHY WAS THIS ANALYSIS CONDUCTED?

A. In our recently completed rate case (Docket No. E002/GR-12-961) the Administrative Law Judge found that, absent other information, she must allocate 41.6 percent of the Program costs to LCM in determining the used and useful aspect of the Program. In addition, this analysis was used to support the Company's after-the-fact modeling efforts explained in the Direct Testimony of Mr. Alders.

I note that during the discovery process we found some errors in Exhibit ___ (TJO-1), Schedule 29 and provided a corrected version to the Department. I include a corrected version of Schedule 29, which was included with the Company's response to the Department's Information Request No. 123, with this Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 30.

I have also provided an update of Exhibit ___ (TJO-1), Schedule 30, which was provided to the Department as Attachment A to the Company's response to the Department's Information Request No. 58. This response is attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 31. The net outcome of the "avoided cost" analysis, 78 percent LCM and 22 percent EPU, did not change. That split was never intended to be used to assess the prudence of our initial decision-making in 2008 but was intended to aid Mr. Alders' modeling effort to show the incremental value of the EPU MWs under current conditions. For purposes of assessing the prudence of our decisions and actions, the Commission should use the split that was developed at the time our decisions and actions were made in 2008.

B. Dr. Jacobs' Analysis of LCM/EPU Costs

Q. DID ANY OTHER PARTY PREPARE AN ALLOCATION OF LCM AND EPU COSTS?

A. Yes, Department witness Dr. Jacobs also prepared an allocation.

Q. DID YOU NOTICE SOMETHING MISSING IN DR. JACOBS' ANALYSIS?

A. Yes. Dr. Jacobs' analysis ignores the needs of Monticello given the age and condition of the existing equipment and also ignores good nuclear practice of basing decisions on the safety and reliability of the Plant. By ignoring these key elements, Dr. Jacobs' approach to the allocation is much different than the Company's. Rather than looking at what costs could have been avoided if the EPU was not pursued, Dr. Jacobs focused on identifying costs that supported the EPU. Thus, Dr. Jacobs did not take into account the age and condition of the equipment prior to the LCM/EPU Program but focused solely on whether could also be used to support the uprate. I find this approach interesting as Dr. Jacobs knew that much of Monticello equipment was worn and obsolete as he noted early in his testimony that the Company "had a policy of deferring capital projects, expecting that Monticello would be shut down and decommissioned in 2010."[53]

Q. WHAT WERE THE RESULTS OF DR. JACOBS' ANALYSIS?

A. Using this approach, Dr. Jacobs concluded that 85.7 percent of the $664.9 million total project costs were for EPU work ($569.5 million) and 14.3 percent ($95.4 million) were not required only for the EPU.

Q. HOW DOES DR. JACOBS' ALLOCATION COMPARE TO THE COMPANY'S ALLOCATION?

A. In Table 10, I list the 10 major modifications and the assignment of costs to LCM, EPU, or a combination thereof as allocated by the Company and Dr. Jacobs.

Table 10. LCM and EPU Allocation Comparison for the Company and Dr. Jacobs

Modification	Xcel Energy's Allocation	Dr. Jacobs' Allocation
Electrical distribution system	LCM (100%)	EPU (100%)
Condensate Demineralizer System Replacement	LCM (75%) EPU (25%)	EPU (100%)
Main and 1AR Transformer Replacement	EPU (9%) LCM (91%)	EPU (Main Transformer 100%) and LCM (1AR Transformer 100%)
Feedwater Heater Replacement	EPU (10%) LCM (90%)	EPU (88%) LCM (12%)[54]
Reactor Feed Pumps and Motors	EPU (7%) LCM (93%)	EPU (100%)
Condensate Pumps and Motors Replacement	EPU (75%) LCM (25%)	EPU (100%)

[53] Jacobs Direct at 3:24-4:1.

[54] Dr. Jacobs categorizes the feedwater heater drain and dumps and valves as both LCM and EPU based on Table 8 of the NRC Letter. In his final allocation, however, Dr. Jacobs attributes this work to LCM.

Modification	Xcel Energy's Allocation	Dr. Jacobs' Allocation
Turbine Replacement	EPU (6%) LCM (94%)	EPU (100%)
PRNM Replacement	LCM (100%)	EPU (100%)
Steam Dryer Replacement	LCM (100%)	LCM (100%)
EPU and MELLLA+ Licensing Costs	EPU (100%)	EPU (100%)

Q. GENERALLY, DO YOU AGREE WITH DR. JACOBS' ALLOCATION?

A. No. Dr. Jacobs' allocation is not reasonable given the state of Monticello at the time we commenced LCM/EPU Program. Prior to the investments made as part of the LCM/EPU Program, Monticello was being managed for retirement. We had avoided making major capital improvements to Monticello as we were not certain that we would be able to operate Monticello beyond the end of its initial license in 2010. Dr. Jacobs' split percentages attribute only $95.4 million of the total project costs of $664.9 million to LCM. In my opinion, we could not have made the necessary repairs that were required to operate Monticello safely and reliably until 2030 on such limited funds given the age and condition of the existing equipment.

Q. WHAT MATERIALS DID DR. JACOBS RELY ON FOR HIS ANALYSIS?

A. To conduct his assessment, Dr. Jacobs relied on a letter I signed on November 5, 2008 to the NRC ("NRC Letter") that lists a majority of the modifications that were performed as part of the LCM/EPU Program. This letter was the Company's resubmitted License Amendment Request application to the NRC.

Q. WHY DID DR. JACOBS RELY ON THIS NRC LETTER?

A. He states that using a contemporaneous document such as the NRC Letter provides the best source for determining the Company's need for each modification. Dr. Jacobs points out that I signed this letter under "penalty of perjury." I want the Commission to understand that I have worked hard at all times to provide accurate information to both the NRC and the State.

Q. DO YOU HAVE ANY CONCERNS USING THIS NRC LETTER TO CLASSIFY MODIFICATIONS AS LCM OR EPU?

A. I have no concerns with the Commission reviewing and relying on this letter. It is truthful and accurate and provides a good summary of some of the work we ended up doing. However, I note that this letter was not written for the purpose of classifying modifications as either LCM or EPU. The NRC was not conducting economic analysis of the split between LCM and EPU nor was the NRC concerned about the cost of the Program. As such, our descriptions of the modifications were for context and convenience rather than to classify the underlying purpose for a modification. Dr. Jacobs incorrectly assumes that this means that all of the equipment was for EPU purposes.

Also, while the letter states that some of the modifications will be sized for "EPU operations," this notation alone should not be used to classify a modification as solely for EPU. In most cases, the age, condition, or design of the original equipment would have required replacement regardless of the EPU. Moreover, the letter, written in 2008, does not take into account the condition of equipment that we later discovered during replacement. In response to the Department's discovery requests, we provided many contemporaneous documents detailing the condition of the existing equipment, including documents included with our response to Information Request No. 124, which is attached to my Rebuttal Testimony at Exhibit ___ (TJO-2), Schedule 32.

For instance, the documents provided in this response include data related to the performance testing performed on the old rotor as part of the generator rewind modification. This document shows that the old rotor failed testing, demonstrating that it was at the end of its useful life and would have required replacement regardless of the EPU. Exhibit ___ (TJO-2), Schedule 32. The generator rewind modification is classified as entirely EPU by Dr. Jacobs.

Finally, the letter actually does contain some descriptions of work that we specifically recognized were needed for LCM purposes. These include:

- 13.8 kV system;
- Main exciter
- M-G set point motors;
- Reactor feed pump discharge check valves.

While Dr. Jacobs says he prefers to rely on contemporaneous documents in his assessment, he ignores the content of the NRC Letter for these modifications.

Q. DID HE PROVIDE A REASON FOR THESE DEVIATIONS?

A. He does for the 13.8 kV system. He claims that I acknowledged in our interview that the 13.8 kV system was not needed absent the power uprate.[55]

Q. IS THIS AN ACCURATE PORTRAYAL OF YOUR COMMENTS?

A. Yes and no. The answer to each question about the uprate is highly dependent on the specific question asked. I believe Dr. Jacobs took my answer out of context.

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[55] Jacobs Direct at 11:22-24.

Q. PLEASE EXPLAIN.

A. During our interview Dr. Jacobs asked me a question similar to the following: "Was it necessary to upgrade to 13.8 kV voltage if you had not done the uprate?" My answer was that a higher voltage may not be required without the uprate. This was an acknowledgment that the decision in 2007 to install 13.8 kV system was precipitated by the need to provide additional electricity to run the larger pumps and motors that were being installed for the uprate. However, this does not negate the longer term need that Monticello had for additional distribution capacity and to replace the aging distribution equipment. It is possible that, absent the uprate, we may have decided to add distribution capacity at a different voltage. Strictly speaking, 13.8 kV was not required absent the uprate but additional distribution capacity whether at 4 kV, 6.9 kV, or 13.8 kV was needed without the uprate. But Dr. Jacobs, for some reason, disregards the contemporaneous information provided to him regarding the need for enhanced distribution margin as well as the fact that space limitations in the existing power block would have required locating the additional bus in the same location. These same space constraints would drive the requirement to run many miles of cable and raceway to accommodate the new system. Thus, the cost of new distribution capacity would not have been avoidable absent the EPU.

Q. ARE THERE SPECIFIC MODIFICATIONS WHERE YOU DISAGREE WITH DR. JACOBS' ASSESSMENT?

A. Yes. I will specifically address Dr. Jacobs' classification of the ten major modifications that account for 95 percent of the costs for the LCM/EPU Program and provide a discussion of the Company's rationale and classification of each modification.

1. *Main Power Transformer*

Q. HOW DID DR. JACOBS CLASSIFY REPLACEMENT OF THE MAIN POWER TRANSFORMER?

A. He considered this modification an EPU-related modification.

Q. WHY DID DR. JACOBS CLASSIFY THIS MODIFICATION AS EPU?

A. He does not provide any explanation for his classification, but the NRC Letter states the Company plans to "replace the existing main generator step-up transformer to provide increased operating margins under EPU conditions."[56]

Q. HOW DID THE COMPANY CLASSIFY REPLACEMENT OF THE MAIN POWER TRANSFORMER?

A. The Company classified replacement of the main power transformer as primarily LCM with a portion (10 percent) attributed to EPU to account for the larger sized transformer that was used to accommodate uprate conditions.

Q. WHY DID THE COMPANY CLASSIFY THIS MODIFICATION AS PRIMARILY AN LCM RELATED MODIFICATION?

A. The Company classified this modification as nearly all LCM because replacement of the 40-year-old main power transformer was necessary due to end-of-life considerations and performance-related issues.

[56] Jacobs Direct at Attachment B at 10.

Q. ARE THERE ANY CONTEMPORANEOUS DOCUMENTS THAT DEMONSTRATE THAT THIS MODIFICATION IS LCM?

A. Yes. A 2001 power point presentation and a 2003 capital projects summary identify the main power transformer for replacement by the Company due to age-related deterioration. Exhibit ___ (TJO-2), Schedules 33 and 34.

Q. ARE THERE OTHER REASONS WHY YOU CLASSIFIED THIS WORK AS LCM?

A. Additionally, we had received a significant operating experience report from INPO, requiring that we inspect the power transformer because industry experience showed it was a vulnerable system and to replace it as necessary. This all led us to conclude that the transformers would need to be replaced regardless of the uprate and replacing this system soon was in the best interest of Monticello.

Q. WERE THERE PERFORMANCE-RELATED ISSUES WITH THE MAIN POWER TRANSFORMER?

A. Yes, the main power transformer was also experiencing performance degradation. Through transformer monitoring, via oil analysis, we determined that there was a gassing problem with the power transformer that was resulting in transformer degradation within the transformer that potentially could lead to in-service failure. This oil analysis was provided as part of our response to the Department's Information Request No. 124 attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 32. Given the end-of-life and performance degradation issues with the existing main power transformer, replacement was necessary to support the extended life of Monticello.

2. 13.8 kV System Upgrade

Q. HOW DOES DR. JACOBS CLASSIFY THE 13.8 KV SYSTEM?

A. Dr. Jacobs' classifies this modification as entirely EPU.

Q. HOW DOES THE NRC LETTER CLASSIFY THE 13.8 KV SYSTEM?

A. The NRC Letter explicitly states that the 13.8 kV upgrade is "an LCM modification to increase margin in the on-site distribution system."[57]

Q. WHY DOES DR. JACOBS CLASSIFY 13.8 KV SYSTEM AS EPU IF THE NRC LETTER STATES THAT IT IS LCM REQUIRED WORK?

A. Dr. Jacobs states that he made up his mind prior to the site visit that the 13.8 kV system was for EPU and that I confirmed during his interview with me that this upgrade was not needed absent the uprate.[58] I addressed my alleged confirmation earlier in my Rebuttal Testimony.

Q. WHAT CONTEMPORANEOUS INFORMATION DID YOU PROVIDE TO DR. JACOBS REGARDING THE 13.8 KV SYSTEM UPGRADE?

A. The Company's responses to the Department's Information Request Nos. 21, 83, and 124 describe that lack of margin on the existing system and the need to install an additional bus to accommodate future electrical loads. Exhibit ___ (TJO-2), Schedules 32 and 35.

Q. HOW DID THE COMPANY CLASSIFY THE 13.8 KV SYSTEM?

A. The Company classified the 13.8 kV modification as entirely LCM consistent with the NRC Letter.

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[57] Jacobs Direct at Attachment B at 13.

[58] Jacobs Direct at 11:10-12.

I note that the Company had identified early on that, in the event the operating license was renewed, the Company would have to address the deficiency in the internal distribution margin. In 2001, the Company identified 4 kV breaker replacement as a necessary modification if the license was renewed as shown in Exhibit ___ (TJO-2), Schedule 33. While we did not decide to upsize the new breakers to 13.8 kV until later, it was clear that additional distribution capacity was recognized as an important LCM need for Monticello.

Dr. Jacobs assumes that the 13.8 kV upgrade was only needed to provide power to the larger reactor feedwater and condensate motors required for EPU. He also states that no other EPU project required this type of modification.

Q. IS IT TRUE THAT NO OTHER EPU PROJECT HAS INCLUDED AN UPGRADE FROM 4 KV TO 13.8 KV? IF SO, WHY WAS THIS UPGRADE REQUIRED AT MONTICELLO?

A. Dr. Jacobs is correct that no other EPU undertaken in the U.S. has included the addition of a new 13.8 kV electrical distribution system. This is because these other plants had acceptable margin in their existing electrical distribution systems to support both the uprate and continued operation. In contrast, the upgrade of the existing distribution system was required at Monticello because it did not have sufficient margin in its system to maintain safe and reliable operations over the course of its extended operating life. Specifically, the existing 4 kV system was more likely to experience trips and additional equipment damage during a fault. As new electrical loads would inevitably be added during the extended life of Monticello the margins would only get smaller. Moreover, while no plant in the United States added 13.8 kV as part of an uprate, several plants have operated with 13.8 kV equipment as part of their original plant design, including Davis-Besse and Palo Verde.

Q. WHY WOULD ADDITIONAL DISTRIBUTION CAPACITY BE NEEDED ABSENT THE UPRATE?

A. Electricity and water are the life blood of a BWR plant, such as Monticello. As a result, it is essential that Monticello have adequate electrical capacity and reliability to support Monticello's operations. The original 4 kV electrical distribution system was designed in the early to mid-1960s. Since Monticello began operations in 1970, it added significant loads onto the original distribution system, including: (i) increased #11 and #12 residual heat removal pump motors from 600 hp to 700 hp; (ii) added emergency filtration train building loads – a TMI Required Modification;[59] (iii) compressed air building loads – upgrade for compressed air system; and (iv) new security building loads – resulting from NRC security requirement changes after September 11, 2001. Each of these additions took up some amount of the existing capacity on the system and eroded the remaining available margins. Thus, the existing 4 kV system was operating with minimal margins which increased the risk of trips or forced outages.

Q. HOW DO YOU KNOW THERE WAS LIMITED ADDITIONAL CAPACITY ON THE EXISTING DISTRIBUTION SYSTEM?

A. The following facts demonstrate the limited additional capacity of the existing distribution system:

[59] This was a modification that was required as a result of the Three Mile Island accident.

- *Industry Standards*. The Institute of Electrical and Electronics Engineers ("IEEE") standards require for new construction a minimum 20 percent bus margin and good design practice has a margin of greater than 50 percent. The reasons for additional margin is two-fold: (1) to prevent a bus trip on under voltage conditions and (2) to ensure that safety related motors are capable of being powered at all times.

- *Margin*. Prior to the LCM/EPU Program, Monticello was operating at a less 1 percent margin. Operating on this narrow of a margin increases the vulnerability of Monticello and limits the operators' ability to respond to events.

- *Motor Start-Up*. The IEEE standards also require that during motor start-up the minimum distribution bus voltage be greater than 80 percent to avoid under voltage conditions. Starting up the existing 6000 hp motors caused voltage to drop to approximately 77 percent of nominal bus voltage.

- *Sequencing*. The Company was experiencing under-voltage conditions starting large motors and pumps and had to manage it by sequencing starting large and competing loads. The Company also installed an under-voltage relay system that acted as a timer on the voltage excursions.

- *Buses*. The existing 4 kV electrical buses were very close to maximum electrical fault ratings prior to the LCM/EPU Program. Specifically, bus #11 was less than 500 interrupting amps from its maximum rating or 99 percent of its maximum rating. Operating in this condition does not allow for any recovery from ground fault related events.

Q. WAS THE COMPANY COMFORTABLE OPERATING THE PLANT IN THESE CONDITIONS?

A. When we believed that the Plant would be shutdown in 2010, we were comfortable that we would operate through the next several years and manage to retirement. No one was comfortable operating the Plant past 2010 with these margins once the potential for a life extension was available to us in 2003.

Q. IF THE COMPANY HAD NOT PURSUED THE EPU, IS IT A FOREGONE CONCLUSION THAT YOU WOULD NOT HAVE PURSUED THE 13.8 KV UPGRADE?

A. No. Without the uprate, we would have undertaken the analysis necessary to determine the optimal configuration and voltage for the electric distribution system for the period of extended operations. While I acknowledge that we may have chosen to stay with 4 kV voltage and added capacity to the existing system, such a decision would have been made only after considerable analysis and it is possible and perhaps likely that we would have decided upon the 13.8 kV (or possibly 6.9 kV) system because of the benefits gained by splitting the safety system loads from the non-safety system loads.

Q. HAD YOU NOT PURSUED THE UPRATE, WHAT ANALYSIS AND WORK WOULD HAVE NEEDED TO BEEN DONE TO THE ELECTRIC DISTRIBUTION SYSTEM?

A. It was clear that the existing 4 kV transformers (1R and 2R) needed to be replaced in any event. These transformers were original plant equipment and had reached the end of their useful life. Whether we changed them to 13.8 kV or replaced them, we would have incurred substantially the same cost. Further, the 4 kV horizontal magnablast breakers and switchgear were original design equipment that were obsolete and no longer supported by the vendor. And the breakers are no longer available and spare parts were difficult to find.

It was also clear that we needed to add new bus work and switchgear. The existing 4 kV system was operating within 50 volts of trip voltage, creating a fairly significant risk of tripping and the need to sequence loads to avoid voltage excursions. Restoring this voltage margin could certainly have been accomplished by adding 4 kV breakers and switchgear rather than going to 13.8 kV. In the scenario where the uprate was not pursued, we would have analyzed whether upgrading to the higher voltage provided incremental benefits beyond adding additional 4 kV breakers.

Q. HOW WOULD YOU HAVE ANALYZED THE DECISION BETWEEN ADDING 4 KV CAPACITY VERSUS ADDING 13.8 KV CAPACITY?

A. As described throughout our filing, we recognized that the reactor feed pumps and motors, the condensate pump and motor and the reactor recirculation MG set were in need of replacement or major overhaul. As part of our analysis we would have considered the appropriate outcome for those motors and whether it was better to replace them with comparable equipment or upgrade them to run on a different voltage. Either outcome could have been supported but it is clear that the decision on what to do with those pumps and motors would influence the choice of distribution system upgrade.

We would have also needed to determine the location of the new switchgear. It is important that the breakers be located near the load they are serving.

This means that we would be limited in the choice of location for the additional breakers regardless of the voltage we chose. As we have described, selection and placement of the 13.8 kV panels was challenging. Had we decided to add to the 4 kV system we would have faced substantially the same questions and obstacles.

Further, we would have had to consider the size of cable to be used, the amount of raceway to be installed, conduit that would need to be strung, fire protection, and foundation size issues. Again, whether we added 4 kV capacity or put in the 13.8 kV system, we would have been faced with substantially similar challenges. I note that the cabling associated with a 4 kV system would not have been smaller and actually might have required larger diameter cable to accommodate the voltage.

Q. WERE THERE ANY REGULATORY CONSIDERATIONS THAT COULD HAVE INFLUENCED THE VOLTAGE SELECTION ABSENT THE UPRATE?

A. Yes. First, evolving regulatory requirements have imposed the need to add electric load to the internal distribution system in the form of Fukushima upgrades, EDG Ventilation System upgrades, and security order impacts. These recent developments would have substantially outstripped the remaining margin in the legacy system and would have triggered the upgrade. Thus, by having installed the 13.8 kV system we were fortunate to have already added sufficient margin on the system to absorb these new loads without additional construction.

Second, I am concerned that certain IEEE requirements may have influenced the choice of voltage. IEEE Standard 141 requires equipment that can withstand ground fault events. Our existing 4 kV switchgear ratings were at the point of being exceeded should new loads be added. This would have resulted in a configuration where entire portions of the distribution system could be irreparably damaged by ground fault(s) if these ratings are not maintained. Repairs associated with these long-lead components could take in excess of a year to manufacture and replace. Without these buses, Monticello would not be able to operate.

Q. HOW WOULD THE COST OF UPGRADING THE 4 KV SYSTEM HAVE COMPARED TO ADDING THE 13.8 KV SYSTEM IN THE SCENARIO WHERE THE COMPANY DID NOT PURSUE THE UPRATE?

A. While I cannot state with certainty because we have not formally studied this alternative path, I can say that it is highly likely that the costs of a comparable 4 kV upgrade would have been substantially similar to what we incurred. Regardless of the voltage, we would likely have chosen an upgrade that (i) split the safety from the non-safety systems, (ii) required construction of new switchgear at the site of the old hot shop or a comparable remote location, (iii) required similar amounts of cable and raceway, and (iv) would have required replacement of transformers and other associated equipment. In the end, my judgment is that the choice of voltage did not drive the costs and we would have incurred most or all of those costs with or without the uprate.

Q. WHAT OTHER FACTORS INFLUENCED THE COMPANY'S DECISION TO CLASSIFY THE 13.8 KV UPGRADES AS LCM?

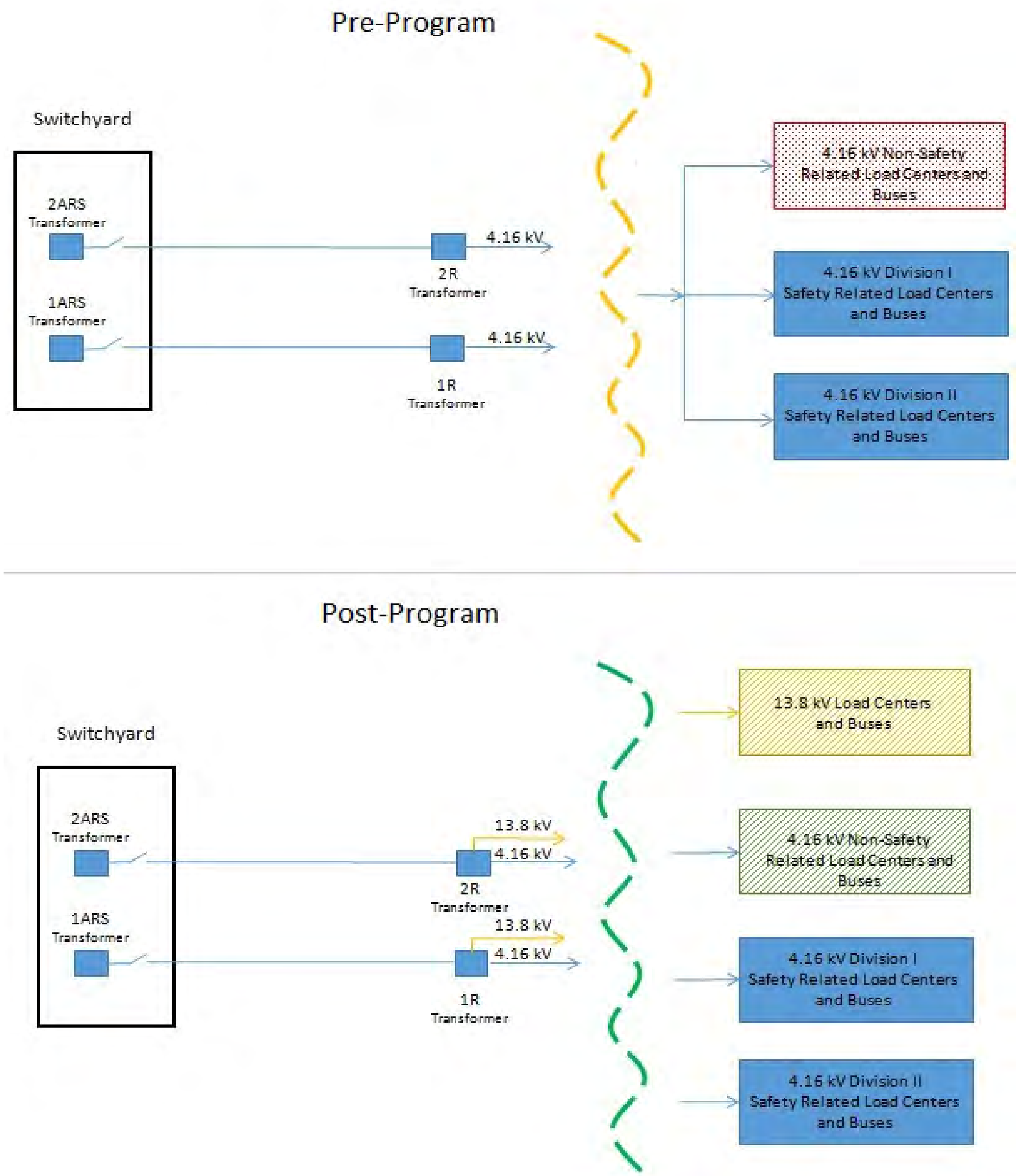
A. Currently, the NRC is examining changes to the rule regarding coping times based on the lessons from Fukushima. Under the NRC's current rule regarding coping times (10 CFR 50.63) Monticello must be able to withstand loss of power for up to four hours. Under the draft rules, this time period could increase to up to 72 hours. This draft rule is expected to be implemented in the 2017 timeframe. To meet this new requirement, Monticello will likely add more battery capacity (direct current) and more battery charging capacity (alternate current). Addition of more battery charging capacity translates into additional load on the distribution system. By adding the 13.8 kV system, we are well-positioned to accommodate additional battery charger load to the Plant's electrical system than we were able to before when there was little margin for new load additions.

Q. WHAT ARE THE BENEFITS OF THE IMPROVEMENTS MADE TO THE DISTRIBUTION SYSTEM?

A. Installing a 13.8 kV system for our non-safety-related equipment allowed us to leave our safety-related equipment on 4 kV, including Monticello's blackout equipment. This not only provided desirable redundancy but also increases the operating margin of our 4 kV system. Figure 4 illustrates this redundancy.

As can be seen in Figure 4, prior to the Program, all safety- and non-safety-related equipment received power from the 4 kV buses (blue lines in Pre-Program diagram). After the 2013 outage and final implementation of the Program, non-safety-related equipment receives power from the 13.8 kV buses (orange lines in Post-Program diagram) while the Division I and Division II safety-related equipment receives power from the 4 kV buses (blue lines in the Post-Program diagram). I note that there is still some non-safety-related equipment that receives its power from the 4 kV buses (grey box in the Post-Program diagram), but the non-safety-related modifications undertaken as part of the Program were all connected to the 13.8 kV buses.

Figure 4. Monticello Electrical Distribution System



Q. WHAT DO YOU CONCLUDE FROM THIS DISCUSSION?

A. First, Dr. Jacobs is wrong when he concludes that the 13.8 kV system was only necessary for EPU. Second, the 13.8 kV system we chose was the right outcome for the Plant, by restoring operating margins and positioning us well to respond to evolving requirements for internal electric demands. Third, regardless of which voltage we selected, the cost of adding new breakers and switchgear would have been substantial.

3. High Pressure Turbine Replacement

Q. HOW DID DR. JACOBS CLASSIFY THE HIGH PRESSURE TURBINE?

A. He considered this modification an EPU-related modification.

Q. WHY DID DR. JACOBS CLASSIFY THIS MODIFICATION AS EPU?

A. He does not provide any explanation for his classification other than to reference the NRC Letter. The NRC Letter states that the Company plans to "replace the existing HP turbine steam path with a new rotor and diaphragms to accommodate the increased steam flow under EPU conditions."[60]

Q. DOES ACCOMMODATING EPU CONDITIONS WARRANT HIS CLASSIFICATION?

A. No. As I testified earlier, the Company made a decision to integrate the LCM and EPU design. As such, almost all efforts, whether or not they would have been undertaken without EPU, were necessarily sized for EPU.

Q. HOW DID THE COMPANY CLASSIFY REPLACEMENT OF HP TURBINE?

A. Even though the new HP turbine was sized to support additional steam flows from the uprate, we determined that the cost of the replacement turbine was comparable whether or not the EPU was undertaken. As a result, we attributed most of the cost to replace the turbine as LCM (99%).

[60] Jacobs Direct at Attachment B at 8.

Q. WHY DID THE COMPANY ATTRIBUTE THE HP TURBINE TO LCM?

A. There are three primary reasons why we attributed this modification to LCM in our "avoided cost" analysis. First, we recognized the existing HP turbine would present end-of-life considerations during the extended operation of Monticello. The first turbine lasted 25 years, and we did not think that the current turbine would last 35 years, regardless of the uprate. Second, replacement was warranted for LCM purposes given the obsolescence of the existing turbine and the need to modernize this equipment to improve reliability and efficiency. Since 1996, when the existing turbine was placed in-service, General Electric has made major advancements in turbine design. Replacing the existing HP turbine with a turbine with an Advance Vortex design provides superior reduction on secondary losses and profile losses. Finally, for a number of years the Company faced a serious and vexing five mil vibration issue on the turbine floor from an unknown source in the rotating element of the turbine. Since the turbine was replaced, the vibration ceased.

4. Feedwater Heaters

Q. HOW DID DR. JACOBS CLASSIFY THE FEEDWATER HEATER MODIFICATION?

A. He considered the feedwater heater modification (13A/B, 14A/B, and 15A/B feedwater heaters, cross-around relief valves, main steam drain tank, feedwater flow transmitters, and feedwater dumps, drains, valves, and piping) an EPU-related modification.

Q. WHY DID DR. JACOBS CLASSIFY THIS MODIFICATION AS EPU?

A. He does not provide any explanation for his classification other than the NRC Letter. The NRC Letter states that the Company plans to replace the "existing 13, 14, and 15 feedwater heaters with new ones sized for EPU conditions."[61]

Q. HOW DID THE COMPANY CLASSIFY THE FEEDWATER HEATERS?

A. In our "avoided cost" analysis, the Company classified the replacement as mostly LCM-related because much of the equipment installed through the feedwater heater modification had reached the end of its useful life and required replacement regardless of the uprate. A portion of the cost was attributed to EPU to account for the increased size of the heaters, piping, and valves necessary to accommodate uprate conditions.

Q. ARE THERE ANY CONTEMPORANEOUS DOCUMENTS THAT EVIDENCE THE NEED TO REPLACE THE FEEDWATER HEATERS FOR THE LONG-TERM OPERATION OF MONTICELLO?

A. Yes. As early as 2001, the Company had identified replacing the feedwater heaters as a necessary project to support a renewed operating license. A 2001 power point presentation, which identifies all six feedwater heaters as a necessary LCM project, is attached as Exhibit ___ (TJO-2), Schedule 33. As a result, the project was placed on Monticello's Long Range Plan.

Further, the Company evaluated the condition of the feedwater heaters, specifically in the context of whether the replacement of the 13A/B, 14A/B, and 15A/B feedwater heaters were an LCM or an EPU requirement in 2006. This document clearly indicates that "[t]his replacement is an LCM item since

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[61] Jacobs Direct at Attachment B at 13.

the existing units could be justified for use under EPU conditions . . . ." Monticello evaluation is included with my testimony at Exhibit ___ (TJO-2), Schedule 36.

Q. ARE THERE OTHER DOCUMENTS THAT WERE PREPARED PRIOR TO THE DATES UNDER WHICH THE DEPARTMENT REQUESTED COMPANY DOCUMENTS?

A. Yes. In our May 22, 2003 Monticello Nuclear Generating Plant Potential Capital Expenditures Strategy document, replacing the feedwater heaters is also listed as a necessary capital project. The Company recognized that the "[s]ervice life of feedwater heaters requires they be replaced to support the extended period of operation." This document is attached as Exhibit ___ (TJO-2), Schedule 34. Pages from this document were provided in the Company's response to the Department's Information Request No. 124.

Q. DESCRIBE THE ISSUES WITH THE EXISTING FEEDWATER HEATERS THAT REQUIRED REPLACEMENT TO SUPPORT OPERATIONS THROUGH 2030?

A. There were several issues with the existing feedwater heaters.

- *Equipment Age*. The feedwater heaters were old. Four of the six feedwater heaters we replaced during the Program were original equipment and the other two were 30 years old. Also, feedwater heaters 15A/B were operating "well beyond their original size rating" prior to replacement and had operated much longer than the experience of our peer utilities. Exhibit ___ (TJO-2), Schedule 36. In fact, in 2010, a tube failure on feedwater heater 15B caused a plant shutdown.

- *Tubing*. We also observed vibration damage at the tube support of the 14 and 15 heaters as well as a certain amount of steam erosion. These heaters experienced service-related degradation, with tube wall thinning and plugging. We had already experienced tube failures. If they were not replaced, they would have required substantial maintenance requiring longer refueling outages to re-tube them.

- *Design*. Feedwater heater designs have changed substantially since they were installed and the replacement brought us up to industry standards.

5. Condensate Demineralizer System

Q. HOW DOES DR. JACOBS CLASSIFY REPLACEMENT OF THE CONDENSATE DEMINERALIZER SYSTEM?

A. Dr. Jacobs classifies this modification as EPU only.

Q. WHAT IS THE BASIS FOR DR. JACOBS' CLASSIFICATION?

A. Dr. Jacobs states that during a site visit to Monticello he learned that replacement of the condensate demineralizer system would not have been necessary without the uprate.[62] Yet, in neither his Direct Testimony nor in response to discovery does he identify the specific facts that were learned to support his conclusion. Dr. Jacobs confirms this in the Department's response to Company Information Request No. 20 attached to my Rebuttal Testimony as Exhibit ___ (TJO-2), Schedule 37.

[62] Jacobs Direct at 13:3-4.

Q. HOW DID THE COMPANY CLASSIFY THIS MODIFICATION?

A. The Company classified this modification as both LCM and EPU in our avoided cost analysis. The Company attributed 25 percent of the costs for replacement of the vessels and piping to EPU given that the vessels were larger for uprate purposes.

Q. WHAT WAS THE BASIS FOR THE COMPANY'S CLASSIFICATION?

A. The Company's decision to replace this system was driven by obsolescence of the existing system and the need to improve the design to increase reliability and function. In fact, replacement of the condensate demineralizer system was originally placed on the Long Range Plan in 2000. *See* Exhibit ___ (TJO-2), Schedule 32. The only portion of this modification that was related to the uprate was the need to install larger vessels to accommodate the higher flows associated with the increased capacity from the uprate.

Q. WHY WAS THE EXISTING CONDENSATE DEMINERALIZER SYSTEM IN NEED OF REPLACEMENT ABSENT THE UPRATE?

A. The existing condensate demineralizer system was in need of replacement to continue the safe operation of Monticello.

- Evidence of age-related deterioration was found in the vessels and filters for this system. By 2010, the vessels and filter elements supported the resin for only six months before needing to be recharged.
- The old analog control system was obsolete and out of date. The need to upgrade and replace the controller was part of our Long Range Plan.

- The flow controllers were pneumatic and replacements were no longer available. A stepping switch controller was also no longer available.
- The old analog control system was challenging from an operational perspective because it required multiple valve manipulations to be performed manually.

The new automated system reduces our reliance on individual operators to consistently run the condensate system and has made the Plant safer and more reliable. Once we decided to replace the controllers, this necessitated replacing all of the wiring, piping, and associated systems due to the difficulty of interfacing the analog components to digital components. During installation, we discovered that the system wiring had substantially degraded to a point where it needed to be replaced regardless of the other circumstances.

6. Reactor Feed Pumps and Motors

Q. HOW DID DR. JACOBS CLASSIFY THE REACTOR FEED PUMPS AND MOTORS?

A. He considered this modification an EPU-related modification.

Q. WHY DID DR. JACOBS CLASSIFY THIS MODIFICATION AS EPU?

A. He does not explain his classification other than the NRC Letter.

Q. WERE THE REACTOR FEED PUMPS AND MOTORS SIZED FOR UPRATE CONDITIONS?

A. Of course. But that does not explain whether replacement was needed for continued operation of the Plant.

Q. HOW DID THE COMPANY CLASSIFY THE REACTOR FEED PUMPS AND MOTORS?

A. Because replacement of the reactor feed pumps and motors was necessary to support long-term operations, but also needed to be sized to support uprate conditions, we allocated costs for this modification 93 percent to LCM and 7 percent to EPU as part of our after-the-fact analysis for modeling.

Q. WHY WAS REPLACEMENT OF THE REACTOR FEED PUMPS AND MOTORS NECESSARY FOR THE LONG-TERM OPERATION OF MONTICELLO?

A. We had identified in our 2001 Long Range Plan that this system was one that was going to need to be replaced to increase plant reliability for the license extension period and that not replacing this component could potentially lead to an extended shutdown, which was an unacceptable risk if the Company was going to seek to extend the license. *See* Exhibit ___ (TJO-2), Schedule 33. The decision to replace the reactor feed pumps and motors was driven by service-related degradation issues and obsolescence.

- *Performance*. The pumps and motors experienced chronic performance problems that could be addressed by replacing them with modern equipment. We anticipated that we would face the need to replace the pumps in the next several cycles (approximately six years) and as a result determined it was prudent to accelerate this replacement.

- *Design*. The original reactor feedwater pumps were a custom redesign of a 3-stage fire pump into a 2-stage feedwater pump. As a result, these pumps were the only ones like it in the world. Our experience with these customized pumps was that they required frequent overhauls during refueling outages. In 2005, the casing of the pumps required substantial repair to address joint leakage issues.

- *Service Life*. While the rotating assemblies had been replaced, the stators were original and had never been re-wound. Given their age, the motors were not designed or expected to remain in-service until 2030, approximately 60 years on a nominally 40-year life.

7. *Condensate Pumps and Motors*

Q. HOW DID DR. JACOBS CLASSIFY THE CONDENSATE PUMPS AND MOTORS?

A. He considered this modification an EPU-related modification.

Q. WHY DID DR. JACOBS CLASSIFY THIS MODIFICATION AS EPU?

A. He does not provide any explanation for his classification other than the NRC Letter. The NRC Letter states that the Company plans to "replace the existing condensate pump internals with new assemblies sized for increased EPU flow rates. Replace the existing 4 kV motors with new 13.8 kV motors sized for EPU operating conditions."[63]

Q. HOW DID THE COMPANY CLASSIFY CONDENSATE PUMPS AND MOTORS?

A. We allocated 25 percent of the cost of these modifications to LCM and 75 percent to EPU in our Direct Testimony.

Q. WHY?

A. Replacement of the condensate pumps and motors was necessary to meet the demand of the larger reactor feed pumps. Specifically, we needed to replace

[63] Jacobs Direct at Attachment B at 12.

the pumps and motors with different models to provide for the increased demand for water to the reactor feed pumps resulting from the uprate.

Q. ABSENT THE UPRATE WOULD THE COMPANY HAVE REPLACED THE CONDENSATE PUMPS AND MOTORS?

A. While there were service-related degradation issues and obsolescence considerations with the condensate pumps and motors, these issues did not require immediate replacement. Without the uprate it is likely that we could have resolved the majority of these issues with the pumps and motors through maintenance and likely replacing the internal components of the pump.

Q. WHAT WERE THE SERVICE-RELATED ISSUES WITH THE CONDENSATE PUMPS AND MOTORS?

A. Regarding service-related degradation, the condensate pump motors were supplied by General Electric as original plant equipment. Performance of the pump/motor combination was degrading and was approaching the point where adequate suction flow/pressure could not be provided to the reactor feed pumps. This degradation indicated that the pumps needed to be replaced before the end of the period of extended life of Monticello.

With regard to the condensate pump motors, retaining the old motors would have required approximately two additional 10-year major bearing replacement preventative maintenance (removing rotors) if EPU was not pursued. In the end, replacing both the condensate pumps and motors improved the operating margins on this equipment and also improved their reliability.

8. PRNM System

Q. HOW DID DR. JACOBS CLASSIFY REPLACEMENT OF THE PRNM SYSTEM?

A. He considered this modification as both an LCM- and an EPU-related modification.

Q. WHY DID DR. JACOBS CLASSIFY THIS MODIFICATION AS BOTH LCM AND EPU?

A. He does not provide any explanation for his classification other than the NRC Letter. The NRC Letter states that the Company plans to "replace the existing General Electric analog system with a General Electric digital system. This is an LCM Modification that includes appropriate design considerations to allow implementation of EPU."[64]

Q. HOW DOES DR. JACOBS ALLOCATE COSTS FOR MODIFICATIONS THAT HE CONSIDERED NECESSARY FOR BOTH LCM AND EPU?

A. He states that his approach was to "only include those costs as EPU costs that were specifically identified as EPU costs" in the NRC Letter.[65] Thus, he places the costs for the PRNM System in the LCM column for simplicity sake but believes that the costs should be both LCM and EPU.

Q. HOW DID THE COMPANY CLASSIFY REPLACEMENT OF PRNM SYSTEM?

A. In our "avoided cost" analysis provided in our Direct Testimony, we classified this modification as entirely LCM given that the 1960s vintage system was in need of replacement due to age and obsolescence.

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[64] Jacobs Direct at Attachment B at 8.

[65] Jacobs Direct at 10:6-8.

Q. WHY WAS REPLACEMENT OF THE EXISTING PRNM SYSTEM NECESSARY FOR THE LONG-TERM OPERATION OF MONTICELLO?

A. With regard to end-of-life considerations, the age of several components of the existing PRNM System meant that these components needed to be replaced or repaired to support operations through 2030. Many of the aging components were individual circuit boards in transmitters, trip units, power supplies, or alarm circuits. As a result, they could be replaced with spare units which had already been replaced or refurbished and then cycled through the same process refurbishment/replacement process. However, there were a number of systems that contained so many individual electronic components susceptible to aging effects that it was impossible to efficiently cycle each subcomponent through such a process while maintaining the operability of the system. Thus, the only feasible solution was a wholesale system replacement.

The prior system was an analog system that presented several operational and practical issues. Due to its age, we had, for some time, difficulty in obtaining replacement equipment. Obtaining replacement parts for portions of the system had already become an issue. General Electric – Hitachi ("GEH") was not expected to support this old analog technology for much longer because the GEH replacement system is a digital system that had been designed for and installed at other sites prior to installation at Monticello. These new digital parts and equipment were incompatible with the existing analog system and cannot be used to repair or replaced analog components.

There are also life-cycle benefits to moving to digital equipment. Specifically, digital reads are more frequent, more accurate, and respond easier to changing conditions in the core.

9. 1AR Transformer and Steam Dryer

Q. ARE THERE ANY MODIFICATIONS WHERE YOU AGREE WITH DR. JACOBS' ALLOCATION?

A. Yes. I agree with Dr. Jacobs that replacement of the 1AR transformer and the steam dryer should be considered LCM only costs.

Q. WHY IS IT APPROPRIATE TO CLASSIFY THE 1AR TRANSFORMER AS UNAVOIDABLE LCM?

A. The 1AR was a used transformer that we acquired from another facility when it was 30 years old. At the time it was replaced, it was approximately 60 years old making it one of the oldest transformers still in service in the United States nuclear fleet. The age of this transformer required its replacement as part of the LCM for Monticello. This transformer was also identified for replacement in the 2001 power point presentation and the 2003 capital projects summary sheet. *See* Exhibit ___ (TJO-2), Schedules 33 and 34.

Q. WHY IS IT APPROPRIATE TO CLASSIFY THE STEAM DRYER AS LCM?

A. The critical factor that led us to classify this modification as mostly unavoidable LCM (86%) was the service-related degradation issues with the existing steam dryer. The original steam dryer was designed in the mid-1960s for a 40-year service life. Prior to replacement, the existing steam dryer was experiencing performance issues. This included an inability to maintain moisture carryover ("MCO") levels. The MCO levels for the original steam dryer were at approximately 0.04 to 0.11 percent prior to replacement and the upper limit for acceptable MCO levels is 0.1 percent.

The most significant impacts of the these high MCO are on flow-accelerated corrosion and shutdown radiation levels. Both impact maintenance on other components in Monticello. Increase in corrosion from high MCO levels in the steam dryer adds to wear on steam related components such as the turbine. High MCO levels also led to an increase in radiation levels which makes maintenance activities on the high pressure turbine more difficult and costly.

As we considered the long-term viability of Monticello, we concluded that replacing the steam dryer would have been necessary for Monticello to remain viable for the extended license period irrespective of the EPU.

Q. WHY DOES DR. JACOBS CLASSIFY THE STEAM DRYER AS AN LCM MODIFICATION?

A. He notes that because the steam dryer was not specifically mentioned in the NRC Letter that he "evaluated the Steam Dryer Replacement and concluded that this work provided sufficient long term operation that I would not include it in the EPU category."[66] While Dr. Jacobs reached the correct result in classifying the steam dryer as LCM, this modification highlights why reliance on a single document to classify costs between LCM and EPU is too simplistic.

Q. PLEASE EXPLAIN.

A. The LCM/EPU Program was a highly complex nuclear initiative and it is unreasonable to make conclusions based on a single document. For the steam dryer, if you look at the 2008 Certificate of Need, the Company classified this

[66] Jacobs Direct at 11:4-6.

modification as an EPU-related modification. If Dr. Jacobs decided to rely on that contemporaneous documentation, then he would have placed the steam dryer in the EPU category. If Dr. Jacobs allocated the steam dryer to EPU along with the other modifications that he also considered EPU, the resulting allocation would be 90 percent EPU and 10 percent LCM. That outcome would be wholly incredible.

Q. DOES THE 2008 CERTIFICATE OF NEED TESTIMONY CHANGE YOUR OPINION THAT THE STEAM DRYER IS AN LCM MODIFICATION?

A. No it does not. As I noted above, the steam dryer replacement was necessary for long-term operation of the Plant given the MCO issues with the existing steam dryer. I simply want to highlight that it is unreasonable to draw conclusions based on a single document for a highly sophisticated nuclear initiative that spanned more than eight years. Rather one must look at the totality of the circumstances and all available documents and information prior to forming any conclusions. This is what the Company did in forming the basis for its "avoided cost" analysis.

C. Like-for-Like Replacement

Q. DR. JACOBS STATES FEWER DOLLARS SHOULD BE ALLOCATED TO LCM WORK BECAUSE THE COMPANY COULD HAVE REPLACED AGING EQUIPMENT USING A LIKE-FOR-LIKE APPROACH THAT WOULD HAVE BEEN LESS COSTLY.[67] DO YOU AGREE WITH HIS ASSESSMENT?

A. I believe that Dr. Jacobs' approach is misguided. If we had not pursued the EPU, we would still have had to do most of the work on an LCM-only basis. Further, as I describe below, like-for-like changes are not as common or as

[67] Jacobs Direct at 14:19-21.

easy as Dr. Jacobs assumes. And in the end, Dr. Jacobs' approach would not be in the best interest of our customers or the long-term viability of the Plant.

Q. PLEASE EXPLAIN.

A. The assumption of "like-for-like" is that a component maintains form, fit, and function identically. This is nearly impossible with components designed and installed in the 1960s. In initiating the LCM/EPU Program we sought to improve the safety and reliability of a 40-year old nuclear facility and position Monticello to operate until 2030. This is reiterated in contemporaneous documents that identify this as one of the key purposes of the Program. It would not have been in the interest of our customers or the state to simply replace the existing old and worn out plant equipment on a like-for-like basis.

For example, it would not have been beneficial to replace the existing condensate demineralizer system on a like-for-like basis. As I previously explained, the existing system was an analog system that required multiple manipulations to be performed manually and required two operators to clean two vessels each week at an estimated time of six to eight hours per vessel. Similarly, the lack of adequate margins on the existing 4 kV distribution system required us to sequence motor start-ups to avoid under voltage conditions. Basically, by advocating for like-for-like replacements, Dr. Jacobs is saying that we should have continued to operate Monticello under these less than ideal conditions. This is not good nuclear practice and I do not believe this is what our customers or our regulators want.

Q. ARE THERE OTHER ISSUES WITH LIKE-FOR-LIKE REPLACEMENTS?

A. Yes. Some of the equipment that was being replaced as part of the LCM/EPU Program was original plant equipment, meaning that it was over 40 years old. Given the age of the equipment, many of the original vendors are no longer in business. As a result, it would be extremely hard, if not impossible, to find a like-for-like replacement.

Q. ASSUMING LIKE-FOR-LIKE REPLACEMENTS WERE AVAILABLE, WOULD THAT HAVE ACHIEVED THE SIGNIFICANT COST SAVINGS AS DR. JACOBS CONTENDS?

A. Even if a like-for-like replacement could be achieved, this would not have resulted in substantial cost savings because the installation and removal costs would be similar. For instance, if the Company decided to replace the existing 4 kV distribution system under a like-for-like construct, we would have had to build a redundant electrical system (*i.e.*, separate buses) to ensure uninterrupted service while the new 4 kV system was installed. This is because the 4 kV safety-related buses are not designed to be taken out of service and are required to operate 24/7. A like-for-like replacement would not have eliminated the need for a separate room to accommodate the new bus work and would not have eliminated the need for 14 miles of new cable and raceway to run all the new cables.

Q. ARE THERE OTHER CHALLENGES ASSOCIATED WITH LIKE-FOR-LIKE REPLACEMENT?

A. Yes. In his Direct Testimony and in response to discovery, Dr. Jacobs uses the example of replacing a steam generator as an "easy" like-for-like exchange where "most replacements were conducted within schedule and budget." *See*

Department response to Company Information Request 26 attached here as Exhibit ___ (TJO-2), Schedule 38. I think Dr. Jacobs is quite wrong.

Like-for-like replacements in the nuclear industry are not simple nor risk-free. We just completed the replacement of the steam generator at Prairie Island Unit 2. That project is currently the subject of the pending rate case and, as described in that proceeding, I would not say the replacement was easy, although I am gratified that Prairie Island successfully went back into service at the conclusion of the installation and is operating well. Unfortunately, not all nuclear utilities have fared as well in the installation of steam generators and I frankly think that Dr. Jacobs picked a bad example.

Q. WHAT HAVE BEEN OTHER UTILITIES' EXPERIENCE IN REPLACING A STEAM GENERATOR AT AN OPERATING NUCLEAR PLANT?

A. In the cases of San Onofre Nuclear Generating Station ("SONGS") in San Diego County, California and the Crystal River 3 Nuclear Power Plant ("Crystal River") in Crystal River, Florida replacements of the steam generators ultimately led to the untimely shutdown of these facilities.

Q. PLEASE DESCRIBE THE STEAM GENERATOR REPLACEMENT AT SONGS.

A. SONGS is a two-reactor PWR nuclear power plant. SONGS consists of two twin units (Unit 2 and Unit 3) each rated at 3358 MWt (1180 MWe). Each of the SONGS units were originally equipped with two CE Model 3340 recirculating steam generators. In a ten-year, $671 million project, Southern California Edison replaced the original steam generators in Units 2 and 3 with new steam generators. The Unit 2 replacement was completed in 2009 and Unit 3 in 2011. On January 31, 2012, Unit 3 suffered a small radioactive leak largely inside the containment shell, with a very small release to the environment, below allowable limits, and the reactor was shut down per standard procedure. On investigation, both units were found to show premature wear on over 3,000 tubes, in 15,000 places, in the replacement steam generators. On June 7, 2013, Southern California Edison announced that it would permanently retire Unit 2 and Unit 3.

Q. DESCRIBE THE LIKE-FOR-LIKE REPLACEMENT OF THE STEAM GENERATOR AT CRYSTAL RIVER THAT LED TO THE SHUTDOWN OF THAT PLANT.

A. The Crystal River is a single reactor PWR owned by Duke Energy that once produced 860 MWe. While replacing two 500-ton steam generators during a scheduled maintenance and refueling outage in October 2009, engineers discovered a delamination, or separation of concrete, within the containment building that surrounds the reactor vessel. Though crews successfully repaired the damage, additional delamination was discovered in two different areas of the containment building in 2011. On February 5, 2013, Duke Energy announced its decision to retire Crystal River.

Q. DO YOU HAVE ANY MORE EXAMPLES?

A. Yes. There was also a problem at Arkansas Nuclear One in Arkansas when equipment being used to move a heavy turbine component failed and fatally injured a person in the area of the move. The cause of the failure at Arkansas Nuclear One was attributed to a design error and failure to load test the device prior to use. The risks of nuclear work are great. That is why it was so important for us to get the work done right.

D. Timing of LCM Upgrades

Q. DR. JACOBS ALSO SUPPORTS HIS ALLOCATION OF A MAJORITY OF THE PROGRAM COSTS TO EPU ON THE BASIS THAT IF THE EPU WAS NOT COMPLETED THAT THE LCM PROJECTS WOULD HAVE BEEN "SIGNIFICANTLY LATER, IF AT ALL."[68] DO YOU AGREE WITH THIS ASSESSMENT?

A. I acknowledge that some of the upgrades that were conducted as part of the LCM/EPU Program were accelerated to maximize long-term savings and to leverage the fact that we were already upgrading related components or systems. However, I disagree with Dr. Jacobs' assertion that these modifications would not have been undertaken at all absent the EPU. Many of our systems were nearing end of life and would have had to be replaced prior to 2030.

Q. WHY WAS IT PRUDENT TO UNDERTAKE THESE UPGRADES AT THE SAME TIME AS THE LCM/EPU PROGRAM?

A. It was prudent to replace components as part of the LCM/EPU Program because it minimized the need to make major investments later on during Monticello's extended life to ensure reliability. Also, by combining this work with the LCM/EPU Program, we were able to achieve economies of scale and eliminate the need to go back to the same system to make additional modifications. Finally, replacing some components ahead of schedule allowed us to get more use out of the component and maximize the depreciation schedule for these significant investments.

[68] Jacobs Direct at 12:15-16.

Q. DID DR. JACOBS SPECIFICALLY IDENTIFY ANY MODIFICATIONS THAT WOULD NOT HAVE NEEDED TO BE REPLACED PRIOR TO 2030 ABSENT THE UPRATE?

A. The Company asked Dr. Jacobs this question during discovery and he stated that he has "not identified specific equipment that would not be needed to be replaced." The Department's response to Company Information Request No. 17 is attached here as Exhibit ___ (TJO-2), Schedule 39.

E. Alternative LCM/EPU Splits

Q. DO YOU THINK THE LCM/EPU PROGRAM SHOULD BE VIEWED AS A WHOLE?

A. Yes. The Project was planned for and constructed as an integrated whole and that is how it should be viewed.

Q. IF THE COMMISSION DECIDES THAT IT WANTS TO IMPUTE COSTS SPECIFICALLY TO THE EPU MWS, WHAT HYPOTHETICAL SPLITS ARE AVAILABLE FOR THE COMMISSION TO CONSIDER REASONABLE FOR RATEMAKING PURPOSES?

A. There are three: (i) the split used by the Commission in the 2008 Certificate of Need, (ii) the "avoided cost" split described in my Direct Testimony, or (iii) the split proposed by Dr. Jacobs. Table 11 provides the Commission with a summary of the splits described in this record:

Table 11. LCM/EPU Split

	LCM	EPU
2008 Certificate of Need Estimate	58.4%	41.6%
O'Connor Direct	78.0%	22.0%
Jacobs Direct	13.5%	86.5%

Q. WHAT DO YOU RECOMMEND?

A. If the Commission decides that it is important to have a hypothetical allocation for its consideration in reviewing the prudency of our effort, we recommend that it choose the 2008 split, as it was based on what we reasonably knew at the time. It was our good faith estimate of the imputed cost of the EPU MWs at the time. While it was always only an estimate, it was of sufficient quality that the Commission used it in the Certificate of Need and in subsequent rate cases. And the Company made its investment decision based upon its good faith reliance on the fact that a majority of the costs to be incurred were targeted for LCM purposes and using an allocation substantially less than that would retroactively change the basis upon which decisions were made.

If the Commission decides that the 58.4/41.6 percent split was not reliable at the time it was used, the Commission could use the split that we provided in Direct Testimony, roughly 78 percent LCM and 22 percent EPU based on our updated analysis as described in Schedules 29 and 30 of my Direct Testimony as updated by Exhibit ___ (TJO-2), Schedules 30 and 31. In any case, the Commission should not use Dr. Jacobs' split as it (i) is inconsistent with focusing on 2008 as the appropriate timeframe and (ii) does not reflect the reality of our situation.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The LCM/EPU Program was a huge undertaking but was successfully implemented. We appreciate the Department's review and analysis of our initial filing. While I respect the Department's criticisms, I am firmly convinced the decisions we made were appropriate and prudent based on the information available to us at the time. In many of the circumstances where the Department questioned why we chose one path over another, we provide an analysis of our decision in our Rebuttal Testimony.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CI-13-754 (Commission Investigation into the Monticello LCM/EPU Project)

Date Request Received: July 24, 2014

Date of Response: August 5, 2014

Person Requesting Information: Timothy J. O'Connor

Response submitted by: Mark W. Crisp

Request No.	
8	Re: Direct Testimony and Attachments of Mark W. Crisp

Reference Crisp p. 20, lines 10-21.

a. Is it your contention that it was imprudent of Xcel Energy to:
   1) begin project design in parallel with licensing and construction activities in 2006?
   2) contract with GE for design work?
   3) select Day Zimmerman/Sargent Lundy in 2007?
   4) transfer some work scope to other contractors in 2010? or,
   5) retain Bechtel in 2011?

b. For each of the above where you answered "yes" please provide a detailed explanation supporting your contention.

<u>DOC Response:</u>

a. The question does not accurately reflect the role of Global Water & Energy in this proceeding. As stated on page 3 of my Direct Testimony:

> Global's assignment is to work with the Minnesota Department of Commerce (Department or DOC) to investigate whether Xcel's actions were prudent. We are to evaluate, from an engineering perspective, whether Xcel's decisions in response to NRC directives, lessons learned from Fukushima, and any other relevant factors in the time since the Commission issued a Certificate of Need (CN) for Monticello were necessary and reasonable.

Continued on next page

My assignment was to “identify the causes and reasons for the cost overruns that have occurred since the project was first approved.” I do not determine that items 1-5 were imprudent; instead I indicate that they contributed to cost increases from the amount the Company first estimated. I concluded on pages 28-29 of my testimony as follows:

Q. **Please explain how the scheduling issues impacted the schedule and budget.**

A. “Fast track” refers to the project management effort requirement to engineer, procure, and construct a project in an abnormally short period of time. In the LCM/EPU project at Monticello, the schedule was to be completed in a single RFO scheduled for 2011.

Unfortunately at the time this schedule was approved by the Xcel Board of Directors, licensing had not begun, design was not started, little if any actual project definition had been accomplished and certainly the overall Project Management Team was not in a position to be responsible for such a project undertaking in this short of a timeframe. An expedited project is successful in meeting schedule, budget and constructability only if all components are completed ahead of the actual implementation.

Projects such as Monticello with (as the Company indicates) a “small footprint” benefit from the time and effort to build a 3-dimensional model on the computer of the activities required to construct the design. Had Xcel not been so aggressive with schedules a 3-D design model would have been invaluable to point out conflicts and construction interferences. It is simply not wise to expedite a project without the benefit of proper project planning on the front end.

Undoubtedly, the expedited approach caused delays and budget increases that could have been avoided with proper pre-planning, project management and proper design sequencing. Proper Project Management and management strategy could have actually supported the 2011 or 2013 refueling outage. Unfortunately, neither of these occurred satisfactorily. The position of the Department of Commerce on the prudency of Xcel’s decisions is addressed in the testimony if Department Witnesses

b. Not Applicable

February 2013

Subsequent License Renewal: Creating the Foundation for Nuclear Plant Operation Beyond 60 Years

> "If the industry's research demonstrates that licensees can safely conduct extended operation beyond 60 years, the NRC has every reason to believe that the licensing reviews will proceed efficiently and effectively."
>
> Gregory B. Jaczko
> Chairman
> U.S. Nuclear Regulatory Commission
> February 22, 2011

Summary: Why Subsequent License Renewal Makes Sense and What Must be Done to Justify It

Federal law and regulation governing the safety of U.S. nuclear reactors currently allow electric companies to renew their nuclear plants' operating licenses for 20 years beyond their original, 40-year license term. The Nuclear Regulatory Commission and nuclear industry are studying whether extending nuclear plants' operating lives beyond 60 years is safe, manageable and economical.

The current nuclear plants' 60-year licenses will begin expiring after 2029. Many years ahead of that date, companies must begin planning either to continue operating those plants or to develop new baseload power. The Nuclear Regulatory Commission (NRC) already has a suitable regulatory framework to review applications for an additional operating period. Before applying for second license renewals, nuclear plant owners and operators must complete extensive research while at the same time deciding whether to replace large, expensive components. Some large components require several years' lead-time to order and once purchased, many more years to amortize and depreciate. Utilities and other nuclear operators need clarity and legal certainty well in advance of these decisions.

Nuclear power plants operating in the U.S. are safe regardless of their age. U.S. nuclear facilities are subject to a rigorous program of daily NRC oversight and inspections and undergo frequent preventive and corrective maintenance, including equipment replacement. Billions of dollars are spent every year to maintain and upgrade nuclear plants to make sure they operate safely and efficiently. Plant operators replace and repair equipment

NUCLEAR ENERGY INSTITUTE
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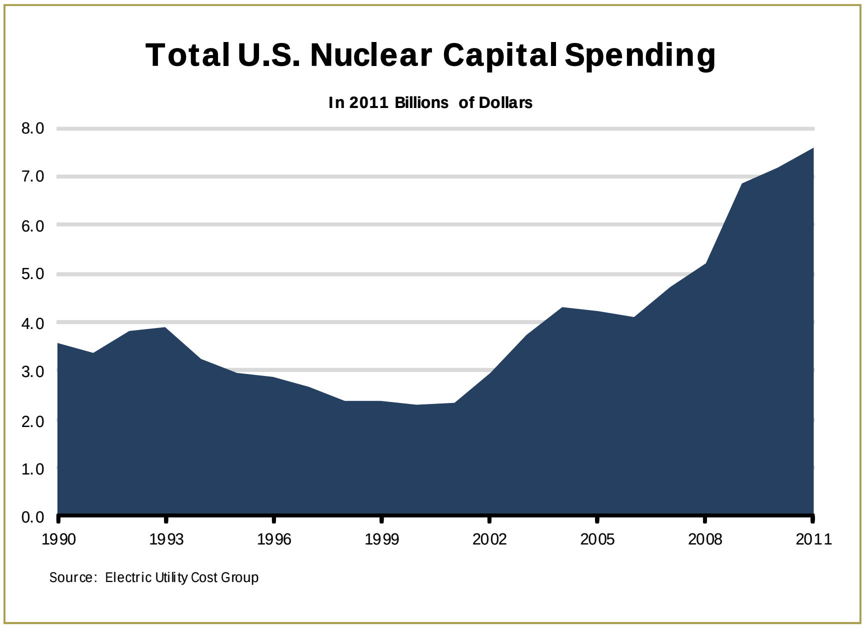
www.nei.org

and components with moving parts, such as pumps and valves, throughout the plant's operational life. Massive multi-ton components like reactor vessel heads and steam generators are replaced for preventive maintenance and enhanced performance. In 2011 alone, the industry invested approximately $7.6 billion in capital projects to upgrade and maintain plant systems.

Life extension makes economic and environmental sense for ratepayers, the community and the utility. Although nuclear facilities require significant capital investment to ensure safe and reliable performance, during operation they are among the least expensive, emission-free sources of electricity.



Research

NRC and the industry are both examining what will be required to operate a nuclear plant beyond 60 years. This work builds on the nuclear industry's track record in safe operation of nuclear plants, and work in developing aging management programs to meet or exceed NRC standards for the first license renewal period.

A more thorough understanding of materials degradation, management of aging components, and the technical basis for continued safety during an additional 20 years of operation is necessary to inform regulatory requirements. This will require fundamental research into replacing, upgrading, and otherwise maintaining underground pipes, electrical cables, concrete, metal and other long-lived materials and components. Programs and actions currently underway include:

- The Department of Energy's **Light Water Reactor Sustainability Program** provides the technical foundations for licensing and managing the long-term, safe and economical operation of current nuclear power plants. This effort focuses on longer-term and higher-risk/reward research, and received $25 million in funding in FY 2012.
- DOE has entered into a **memorandum of understanding** with NRC and the Electric Power Research Institute (EPRI) to cooperate on research related to the long-term operation of existing plants.
- The NRC is revising its **Expert Panel Report on Proactive Materials Degradation Assessment** to include longer time frames and passive long-lived structures and components. This effort will allow NRC to identify significant knowledge gaps and any new forms of degradation that may have arisen since it developed its original proactive materials degradation assessment; capture the current knowledge base on materials degradation; and help prioritize materials degradation research needs and directions for future efforts.

- The NRC is working with other U.S. agencies and nongovernmental organizations to implement an **International Forum for Reactor Aging Management** to exchange information on operating experience, best practices, and emerging knowledge. This will help pool technical expertise and avoid unnecessary or redundant research into materials degradation and aging management undertaken in recent years.

- DOE and NRC have already held **joint workshops** in February 2008 and February 2011 to facilitate discussion among these agencies and the industry, national laboratories, academia, and the public in such areas as aging of systems, structures and components, materials degradation, diagnostic and prognostic technologies, and future technical and research requirements to continue operation beyond sixty years.

"I don't think I've heard any challenge to the concept of operating the nuclear plants beyond 60 years ... of course [they] won't operate beyond 60 years if they aren't demonstrated to be safe."

Neil Wilmshurst
Electric Power
Research Institute

Regulatory Framework

The research to support a utility's decision to invest in lifetime extension and comply with NRC licensing requirements is well underway. The regulatory framework should be in place a decade or more before licenses expire to facilitate planning.

The NRC maintains a comprehensive licensing framework for license renewal. This process is suitable for evaluation of an additional license period and should require only minor updates to guidance documents. The current license renewal process considers both safety-related and environmental impacts. An applicant should be prepared to address the technical aspects of plant aging and describe the ways it will be managed to ensure health and safety of the public. The applicant must also evaluate the potential impact on the environment if the plant operates for another 20 years. Because a renewed license does not guarantee the right to continue operations, nuclear plant operators must continue to meet NRC requirements or the NRC may order a reactor to shut down at any time.

Technology	Jobs/ MWe	Average Size (MWe)	Direct Local Jobs	Workforce Income ($ Million/year)
Nuclear	0.50	1,000	504	$32.49
Coal	0.19	1,000	187	$10.99
Hydro > 500 MW	0.11	1,375	156	$10.79
Hydro Pumped Storage	0.10	890	85	$6.70
Hydro > 20 MW	0.19	450	86	$5.79
Concentrating Solar Power	0.47	100	47	$2.62
Gas Combined Cycle	0.05	630	34	$2.02
Solar Photovoltaic	1.06	10	11	$0.33
Micro Hydro < 20 MW	0.45	10	5	$0.33
Wind	0.05	75	4	$0.29

Source: Donald Harker and Peter Hans Hirschboeck, "Green Job Realities—Quantifying the Economic Benefits of Generation Alternatives," Public Utilities Fortnightly, March 2010, http://www.fortnightly.com/exclusive.cfm?o_id=379.

Benefits of Life Extension

Economic

The average 1,000 megawatt nuclear reactor generates approximately $470 million in economic output and more than $40 million in total labor income every year. These sums include the plant's expenditures for goods, services and labor as well as spending attributable to the presence of the plant and its employees as expenditures filter through the local economy (e.g., housing, food).

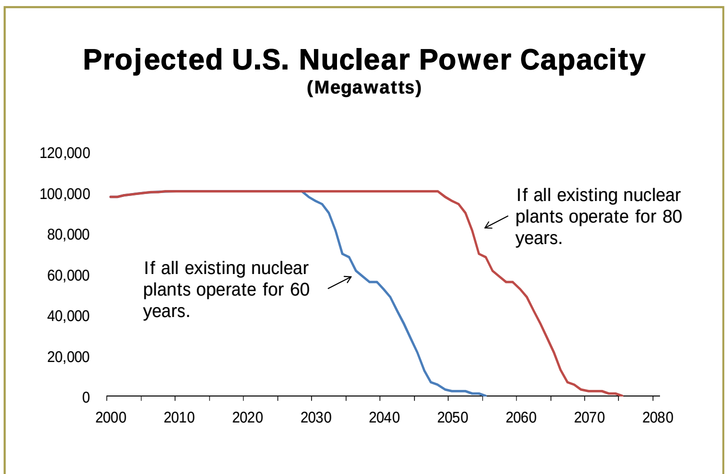
The average nuclear reactor also generates $16 million in state and local tax revenue

annually. These tax dollars pay for schools, roads and other infrastructure. The average nuclear plant pays approximately $67 million annually in federal taxes.

Over 20 years (the typical period of a renewed license), one nuclear unit will generate $9.4 billion of economic output, $800 million in labor income, $320 million in state and local taxes and $1.3 billion of federal tax revenue.

Environmental

Even with aggressive expansion of nuclear energy, the United States will nonetheless lose substantial capacity to generate clean energy without extending the lives of nuclear power plants beyond their first license renewal terms.



Sources: Capacity—Energy Information Administration; License Expiration—Nuclear Regulatory Commission

Over 20 years, the amount of CO_2 avoided by one nuclear unit would be more than 120 million metric tons. This is equal to 5 percent of the CO_2 emissions from the entire electric sector in 2011 (2.3 billion metric tons).

National Strategic Interest

In February 2011, the Assistant Secretary of Energy for Nuclear Energy, Peter Lyons, stated that there exists a "national strategic interest in the long-term operation of existing plants," to support climate change objectives and enhance U.S. energy security.

Path Forward

Reliable and efficient nuclear power plants demonstrate their value every day. Nuclear energy provides low operations, maintenance and fuel costs while providing a hedge against future environmental regulations to limit carbon dioxide. Utilities and other nuclear operators need clarity and legal certainty right now—from research as well as national energy policy and regulation—to make decisions about operating reactors beyond 60 years. Renewing licenses at nuclear power plants will ensure a continued, reliable, clean supply of electricity to satisfy the increasing demands of the digital economy.

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■

Monticello Extended Power Uprate Project Costs by Transaction Source - CWIP, AFUDC, & RWIP by Year
March 31, 2014

	Records	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Actual 2014 to 3/31	Actual Through 3/31/2014	Forecast Remaining 2014	Grand Total
CWIP															
JE															
	4,635			(13)	(234,896)	973,546	306,465	791,233	(196,370)	(755,006)	657,666	43,318	1,585,943		1,585,943
Accruals	9,383				7,400	952,025	9,565,491	(5,096,121)	4,011,039	-1,711,544	(7,332,672)	(66,753)	328,865		328,865
Accruals - Final	88										5,139,851	338,135	5,477,986		5,477,986
Allocations	2,899										(109,644)		(109,644)		(109,644)
NMC Entries	185	795,026	13,756	821,121	2,942,032								4,571,935		4,571,935
O&M to Cap Xfers	952					175,120	1,494,393	272,117	2,080,464	55,157	3,855,427	9,069	7,941,747		7,941,747
Prepay	7							(10,000,000)	8,500,000	1,500,000			-		-
Sales Tax Refund	147					(3,920)	(4,749,556)	(1,811,688)	(1,194,266)	(127,893)	(219,144)		(8,106,467)		(8,106,467)
Transfer	38												-		-
Transfer - FWH	419												-		-
Transfer - GE	13												-		-
Transfer - License	138												-		-
Transfer - Non-EPU	129								(863,001)	(2,601,804)			(3,464,805)		(3,464,805)
Transfer - RWIP	9								(18,589,890)				(18,589,890)		(18,589,890)
JE	19,042	795,026	13,756	821,108	2,714,536	2,096,771	6,616,793	(15,844,459)	(6,252,024)	(3,641,090)	1,991,484	323,769	(10,364,330)	-	(10,364,330)
OVERHEAD															
E&S	15,057					263,303	5,727,164	1,330,939	3,677,596	833,376	963,816		12,796,194		12,796,194
PwrPlant	1,236	1,268	2	2,219	16,595	69,955	176,820	1,196,838	1,820,137	576,629	254,074	8,319	4,122,856	(51,600)	4,071,256
PASSPORT															
AP / CM	52,199			6,135,498	12,832,250	68,121,980	91,812,771	84,447,462	142,165,841	43,897,543	123,893,407	798,634	574,105,386	(4,878,253)	569,227,133
IM / PO	29,631					124,515	2,145,712	864,885	2,639,469	909,480	4,806,592	468	11,491,121		11,491,121
PAYROLL															
Non Prod JE	3,145					(6,155)	(3,089)	7,371	(510)	1,269	3,026		1,912		1,912
TIME	19,217			27,987	141,561	2,410,203	9,909,031	3,260,217	10,330,297	2,459,142	16,181,431	226,726	44,946,595	419,170	45,365,765
TIME Non Prod	3,176					298,654	326,864	301,083	347,473	242,817	323,864	27,830	1,868,585	51,350	1,919,935
EXPENSES															
Expense Reports	3,087					175,377	138,302	196,552	212,682	58,345	46,697	3,369	831,324		831,324
Totals -CWIP Only	145,790	796,294	13,758	6,986,812	15,704,942	73,554,603	116,850,368	75,760,888	154,940,961	45,337,511	148,464,391	1,389,115	639,799,643	(4,459,333)	635,340,310
AFUDC															
AFUDC Debt		11,976	25,858	101,363	679,464	2,610,821	4,712,644	6,129,323	6,607,715	5,589,732	3,852,203		30,321,099		30,321,099
AFUDC Equity		18,468	28,224	149,048	841,710	4,014,317	7,513,550	10,824,826	12,088,145	10,339,588	8,612,255		54,430,131		54,430,131
Totals With AFUDC		826,738	67,840	7,237,223	17,226,116	80,179,741	129,076,562	92,715,037	173,636,821	61,266,831	160,928,849	1,389,115	724,550,873	(4,459,333)	720,091,540
RWIP						5,191	1,858,946	317,977	18,945,890	1,703,928	5,258,007	(50,924)	28,039,015		28,039,015
Grand Total with AFUDC		826,738	67,840	7,237,223	17,226,116	80,184,932	130,935,508	93,033,014	192,582,711	62,970,759	166,186,856	1,338,191	752,589,888	(4,459,333)	748,130,555
Expenditure Total - CWIP and RWIP Only (without AFUDC)													667,838,658	(4,459,333)	663,379,325

Note: The highlighting can be used to cross reference the same numbers in DOC-84 Attachment A.

Nuclear License Renewal

Governance Council

July 15, 2003

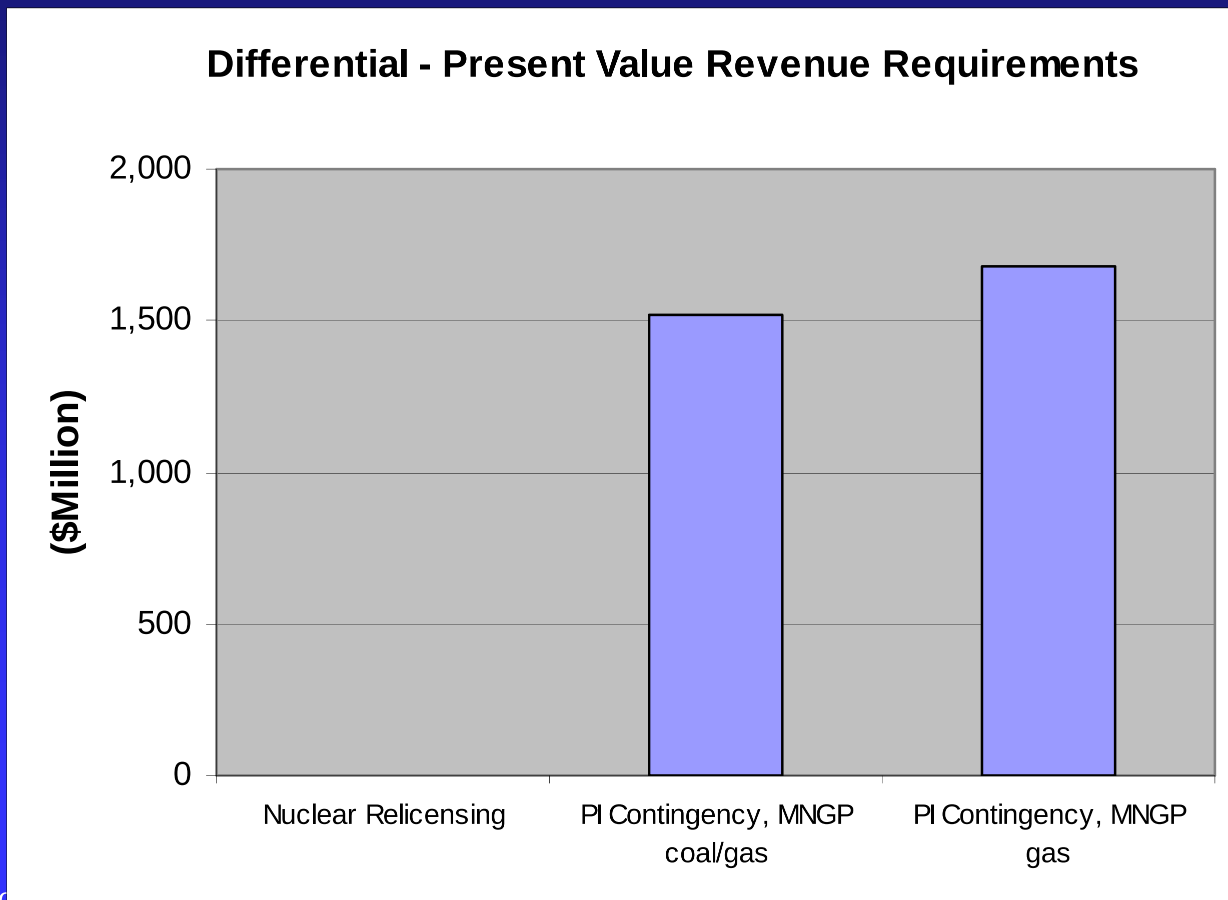
Outline

- License Renewal
  - Benefits
  - Description of License Renewal Process
  - License Renewal Costs
- MN Certificate of Need Process
- Environmental Benefits
- Related Issues
  - Reactor Vessel Head Replacements
  - PI-2 Steam Generator Replacement
  - Potential Power Uprates
- Final Recommendations

Why Relicense?

- Cost benefit
  - $1.5B benefit for ratepayers
- Major Advantages
  - Cost beneficial to customers
  - Clean air compliance
    - No Greenhouse Gas penalties
    - No increase in SO2

Projected Cost Benefit

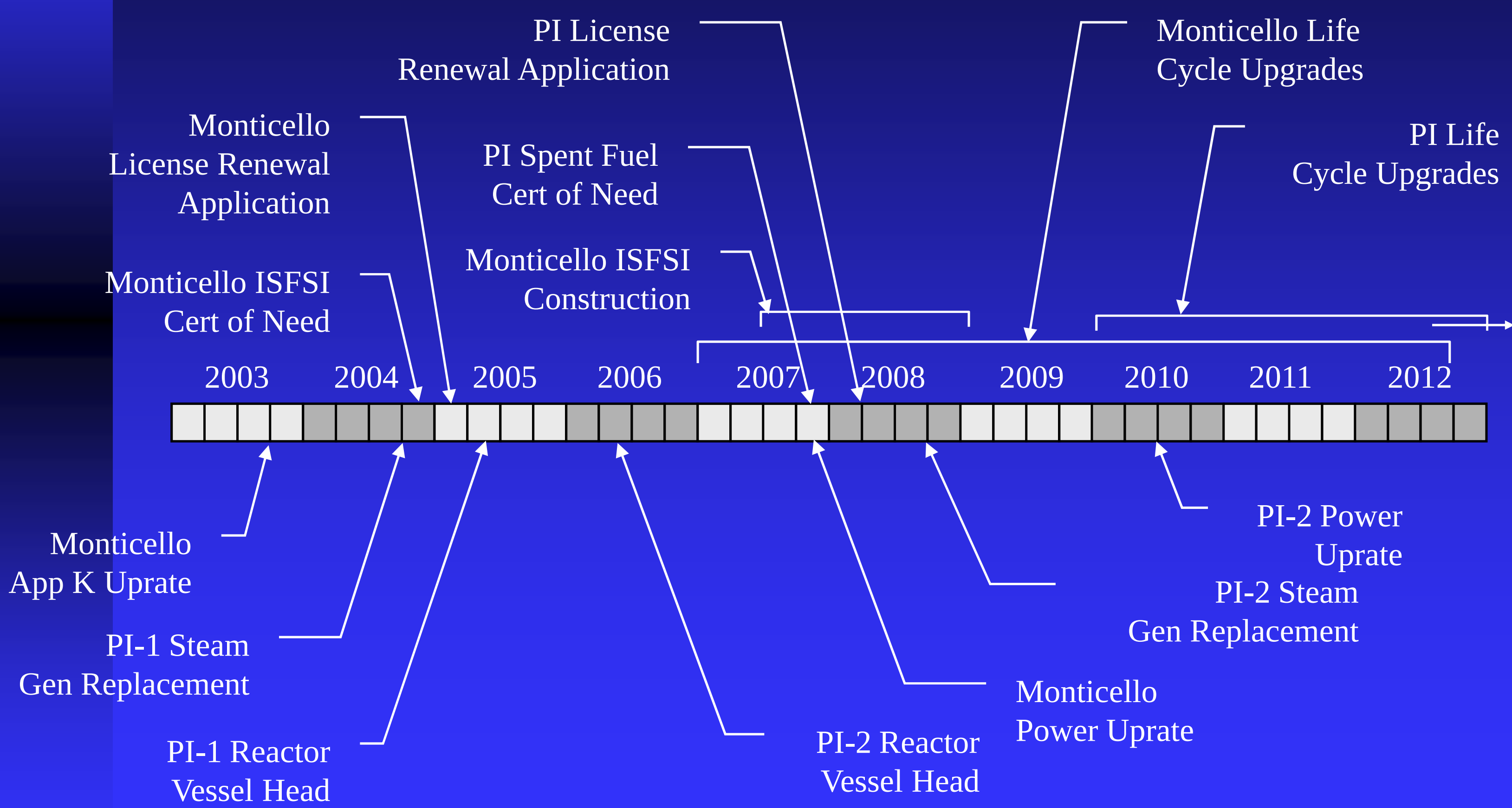


License Renewal Process

NRC License Renewal

- Original 40-year license term
  - Based on economic and antitrust considerations
  - Not based on limitations of nuclear technology or real equipment life
- NRC License Renewal process
  - Defined in 10 CFR 51 and 10 CFR 54
  - Submit 5 years prior to license expiration

Key Nuclear Activities – 10-year



License Renewal Process

- Application
  - Identify any reactor system, structure and component affected by license renewal
  - Demonstrate - safely manage the adverse aging effects during renewal period
  - Analyze environmental effects of extended reactor operation
- NRC makes safety decisions & presents findings to Advisory Committee for Reactor Safeguards (ACRS)
- Public participation allowed at several points

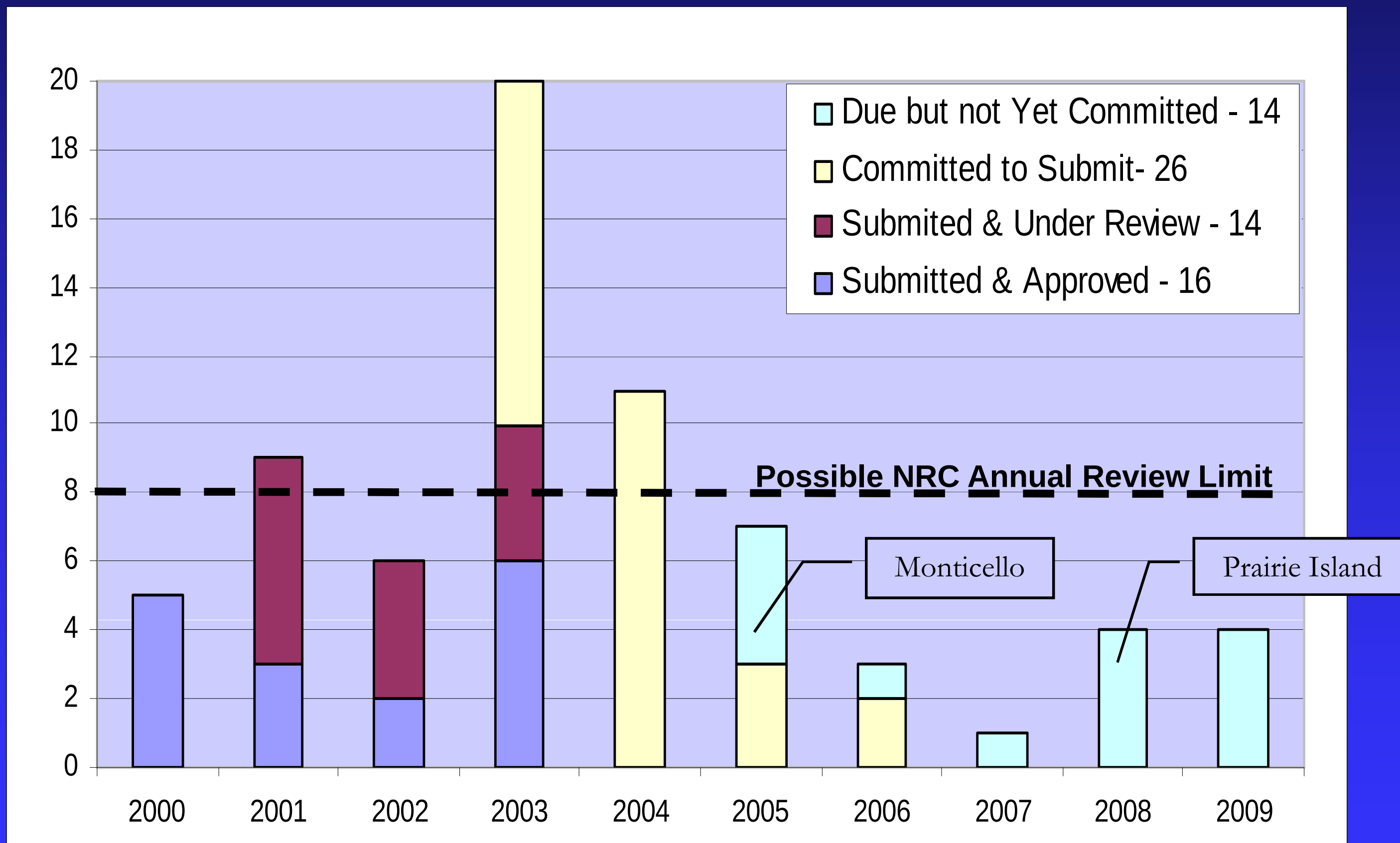
Key Components of Application

- Environmental Review
  - Generic EIS (NUREG-1437)
    - Assessed scope and impact of generic license renewal concerns
  - Site-specific supplement is required for each site's license renewal
  - Public "scoping" meeting

NRC License Renewal

- Review Time
  - If hearing is required: 30 months
  - No hearing: 22 months
- NRC Inspection Program
  - Implemented prior to approval of renewed license
  - Verify that applicant meets rule requirements and has implemented license renewal programs

License Renewal Status



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NRC License Renewal

Renewal Application - Industry Experience

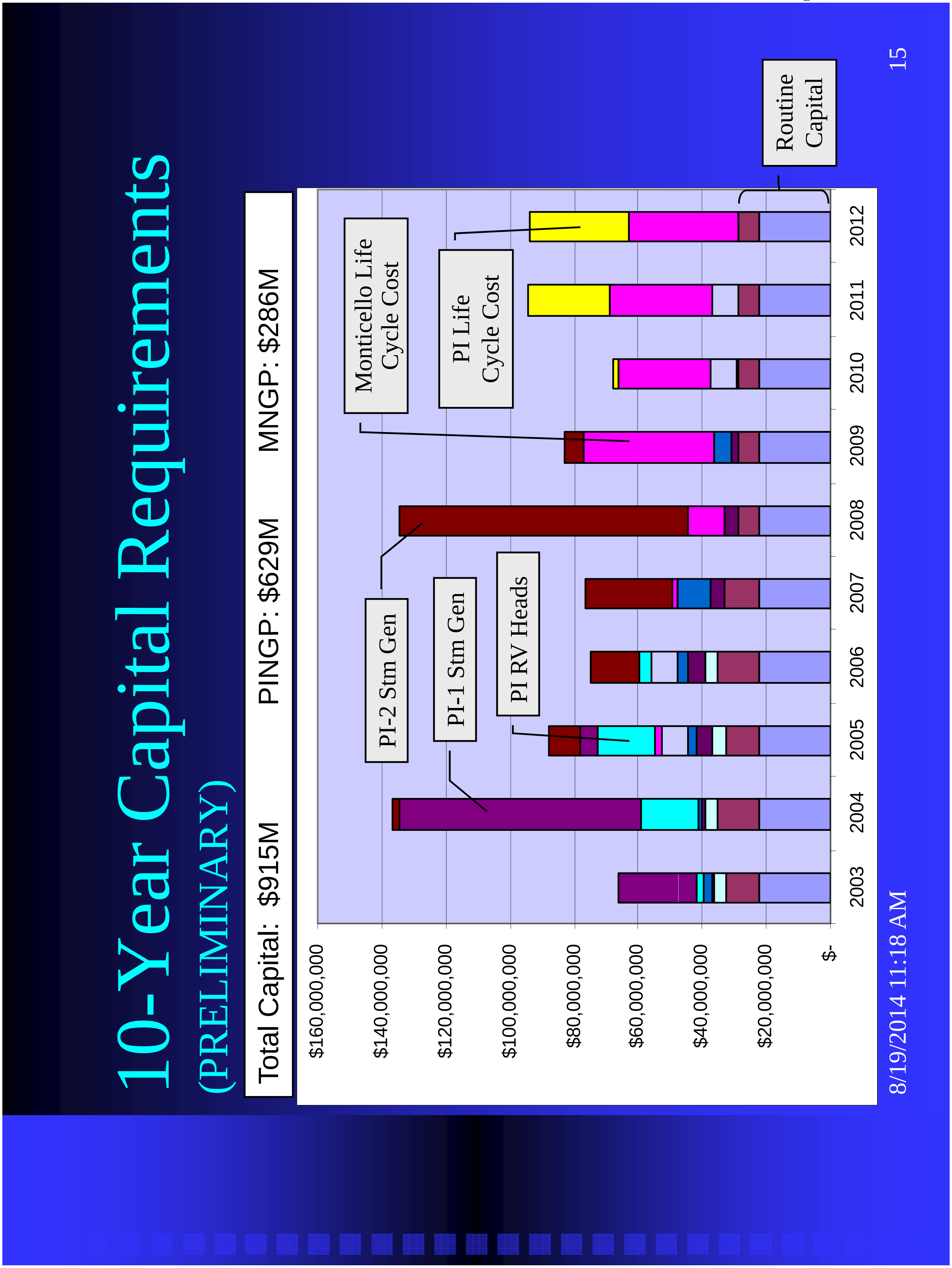
Reactor/Owner	Project Duration (months)	Project Hours (x1000)
Farley/Hatch (Southern)	30	120-140
Peach Bottom (Exelon)	30	100
Point Beach (We Energies)	30 (est.)	127 (est.)
Monticello	30 (est.)	116 (est.)

Monticello project cost - $18M est.

Life Cycle Management Costs

10-Year Capital Requirements
(PRELIMINARY)

Monticello	License Renewal	16,760,000
	Life Cycle Costs	151,500,000
	Power Uprate	24,700,000
	General Capital (*8 yrs)	93,400,000
Prairie Island	License Renewal	22,460,000
	Life Cycle Costs	57,700,000
	Rx Vessel Heads	42,000,000
	U1 Steam Generator	104,900,000
	U2 Steam Generator	150,000,000
	Power Uprate	32,000,000
	General Capital	220,000,000
TOTAL		915,400,000
Committed through EOL (est.)		$ 379,600,000


10-Year Capital Requirements
(PRELIMINARY)
Total Capital: $915M
PINGP: $629M
MNGP: $286M
$160,000,000
$140,000,000
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$-
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
PI-2 Stm Gen
PI-1 Stm Gen
PI RV Heads
Monticello Life Cycle Cost
PI Life Cycle Cost
Routine Capital
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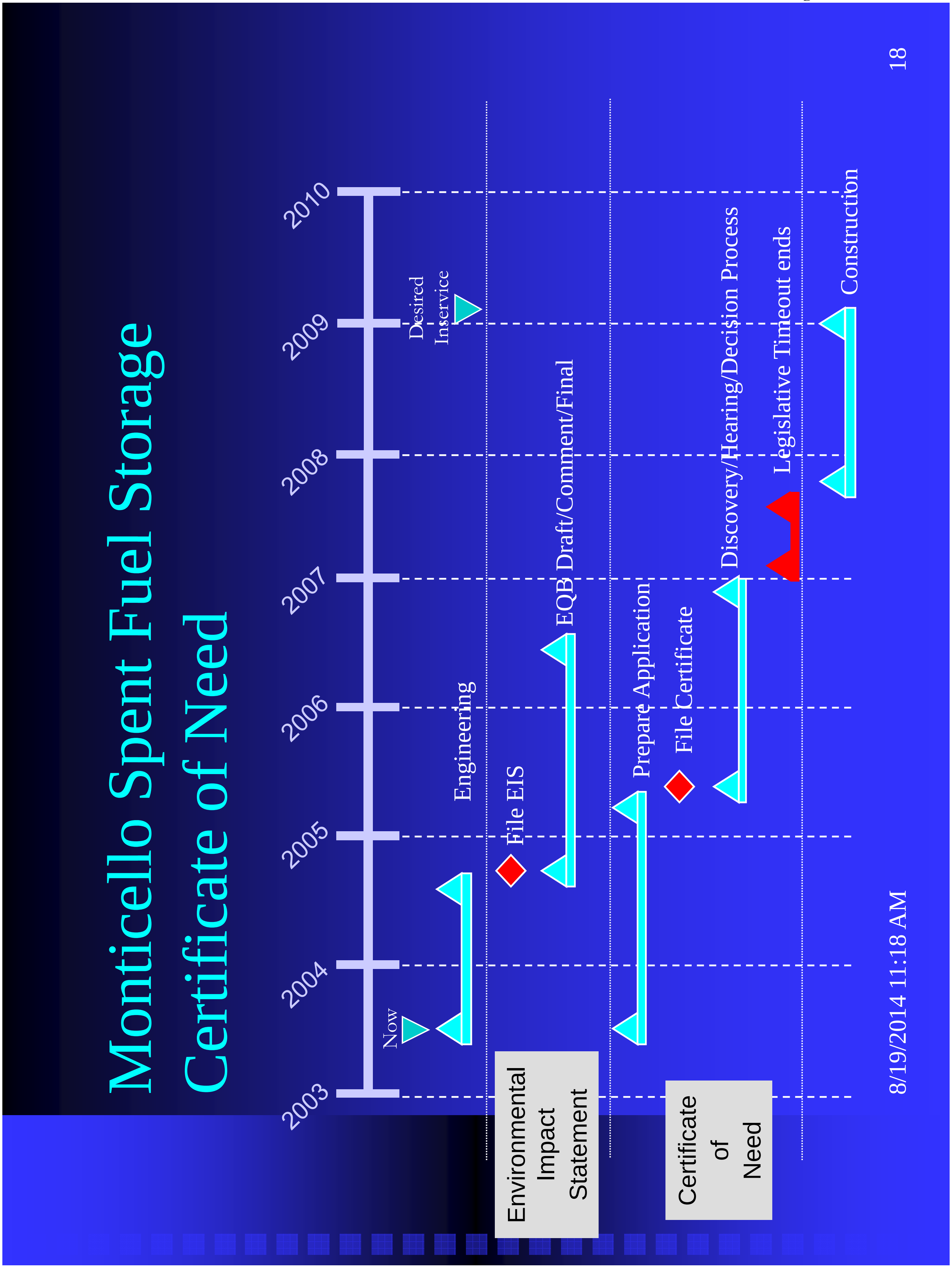
Minnesota Certificate of Need Process

MN Certificate of Need

- Need to submit request for CON for License Renewal/ISFSI
  - Expect application to be extremely contentious
  - Will include license renewal information to substantiate basis and need for ISFSI
  - Power Uprates will make effort more challenging


Monticello Spent Fuel Storage
Certificate of Need
2003
2004
2005
2006
2007
2008
2009
2010
Now
Desired
Inservice
Environmental
Impact
Statement
Engineering
File EIS
EQB Draft/Comment/Final
Certificate
of
Need
Prepare Application
File Certificate
Discovery/Hearing/Decision Process
Legislative Timeout ends
Construction
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MN Certificate of Need

- Key Factors
  - Several CON's may be required:
    - Monticello ISFSI to support License Renewal
    - Prairie Island additional spent fuel storage to support License Renewal
    - Power Uprates
  - Start process now for Monticello ISFSI
    - Necessary to meet due date of Aug 2004 for submitting EIS to Minnesota


Environmental Benefits

Clean Air Act Advantages

- Many states developing new approaches to clean air compliance
- Incremental emission-free generating capacity
  - Nuclear generation can offset greenhouse gas requirements
  - Power uprates can offset greenhouse gas increases


Other Issues
PUC/Legislature
Regulatory Treatment
Rate treatment
Depreciation schedule
Operational Risk
Need improved site financial controls
Control annual O&M spending
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Related Issues

- Reactor Vessel Head Replacement
- PI – 2 Steam Generator Replacement
- Power Uprates

Reactor Vessel Head Replacement

- Expected inspection costs: $40 - $70M
  - Each visual inspection - $4M - $7M
- Estimated replacement cost: $42M
- Has not been discussed with regulators/legislators
- Project likely justified through end of license
  - Inspections begin in 2005 & 2006
  - $2M committed for long-lead time materials
  - Need to issue 1st contract by 9/15

Related Issues

- PI-2 Steam Generator Replacement
  - Investigating delay from 2008 to 2010
- Power Uprates
  - 150Mw – 190Mw possible
- Will be handled through annual capital budgeting process

Governance Council Request

Governance Council Request

- Monticello License Renewal Application
  - Approve $17.5M to prepare license application
  - Approve NRC notification of intent to submit Monticello LRA in Q1 2005 (reserve place in queue)
- Proceed with PI Reactor Vessel Head business cases
  - Approximately $42M
  - Seek approval within next 60 days
- Begin preparation of detailed business cases
  - Board approval Q3 2004
  - Submit CON to State of MN Q3 2004
  - Submit LRA to NRC Q1 2005

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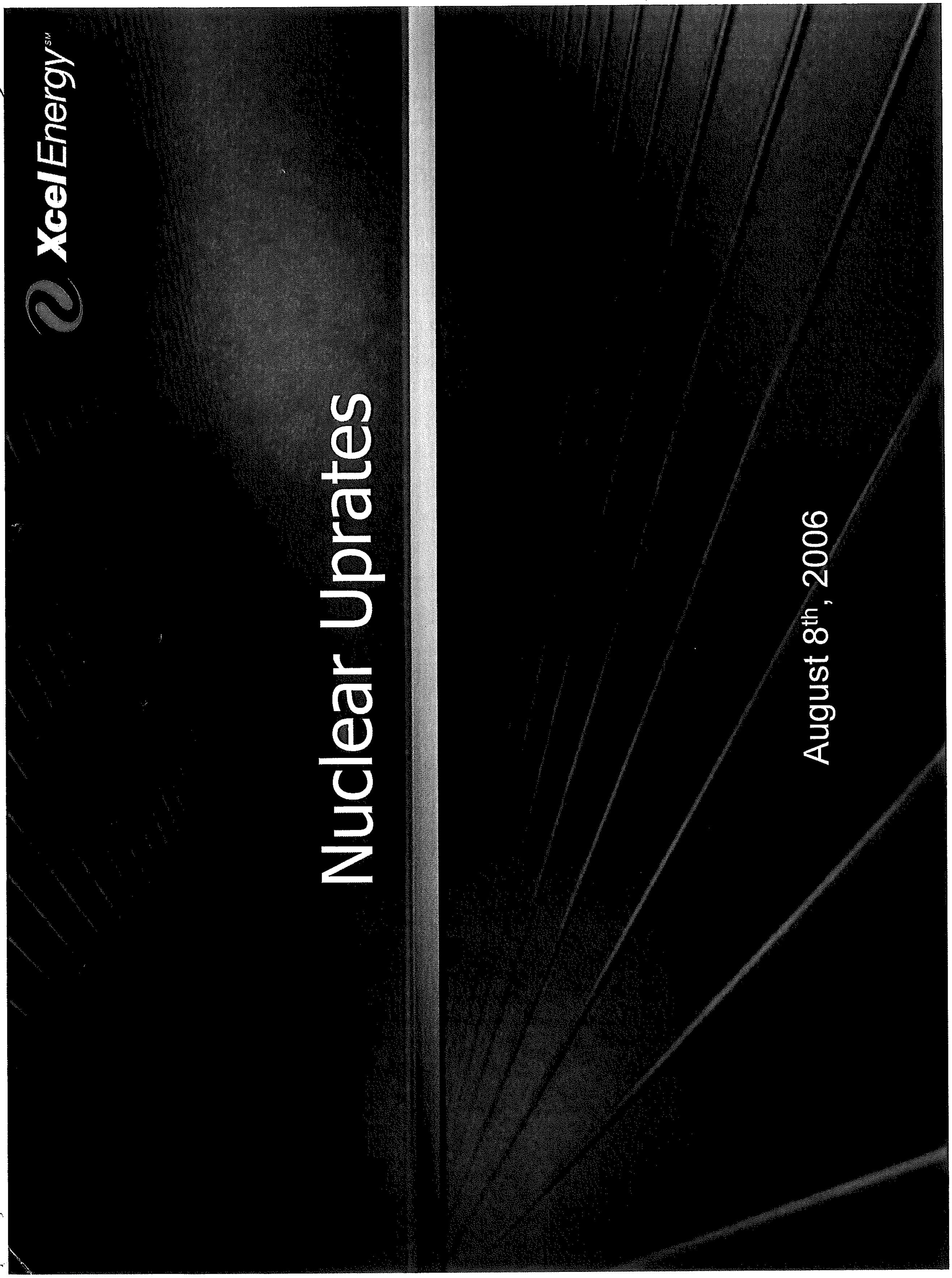
Financial Council Meeting Agenda
August 8, 2006
2:30 p.m. – 4:30 p.m. CT
Committee Room – Minneapolis
Call in – 612.330.6677 ID – 4840

- 2:30 – 3:00 — NSPM Big 3 Host Community Revenue Stabilization Project Update – K Larson; J Duevel; C Lesher; D Lahr
  - Excelsior
- 3:00 – 3:25 — NSPM Resource Plan - Update on Sherco, Monticello and Prarie Island Uprates – K Haeger; C Bomberger; G Hudson
- 3:25 – 3:45 — Alamosa Solar RFP – Kurt Haeger; Mark Mcgree
- 3:45 – 4:15 — NSPM Coal Transportation Contract Update – T Imbler
- 4:15 – 4:30 — Open Discussion

Initial Review of Mankato
LCM/EPV
$273.8 together


Xcel Energy
Nuclear Uprates
August 8th, 2006

Summary – Nuclear Uprates

	Uprate	In-Service	Cost
Monticello	69 – 73 Mw	2009-2011	$1600/kW

- **Monticello**
  - **assumes $6M repair of steam dryer in cost estimate**
  - **Turbine installation in 2009 nets 35 MW; generator and transformer replacement in 2011 nets additional 35Mw**

Nuclear Uprates

- Costs are driven by need to start Monticello activities in 2006:
  - Support submission of NRC PU application
  - Engineering to support ordering hardware by early 2007
- Estimates DO NOT include:
  - Costs to prepare the Nuclear CON's for power uprates
  - Costs for MISO Transmission costs
  - Costs for Life Cycle Management Costs (costs are included in current budgets)

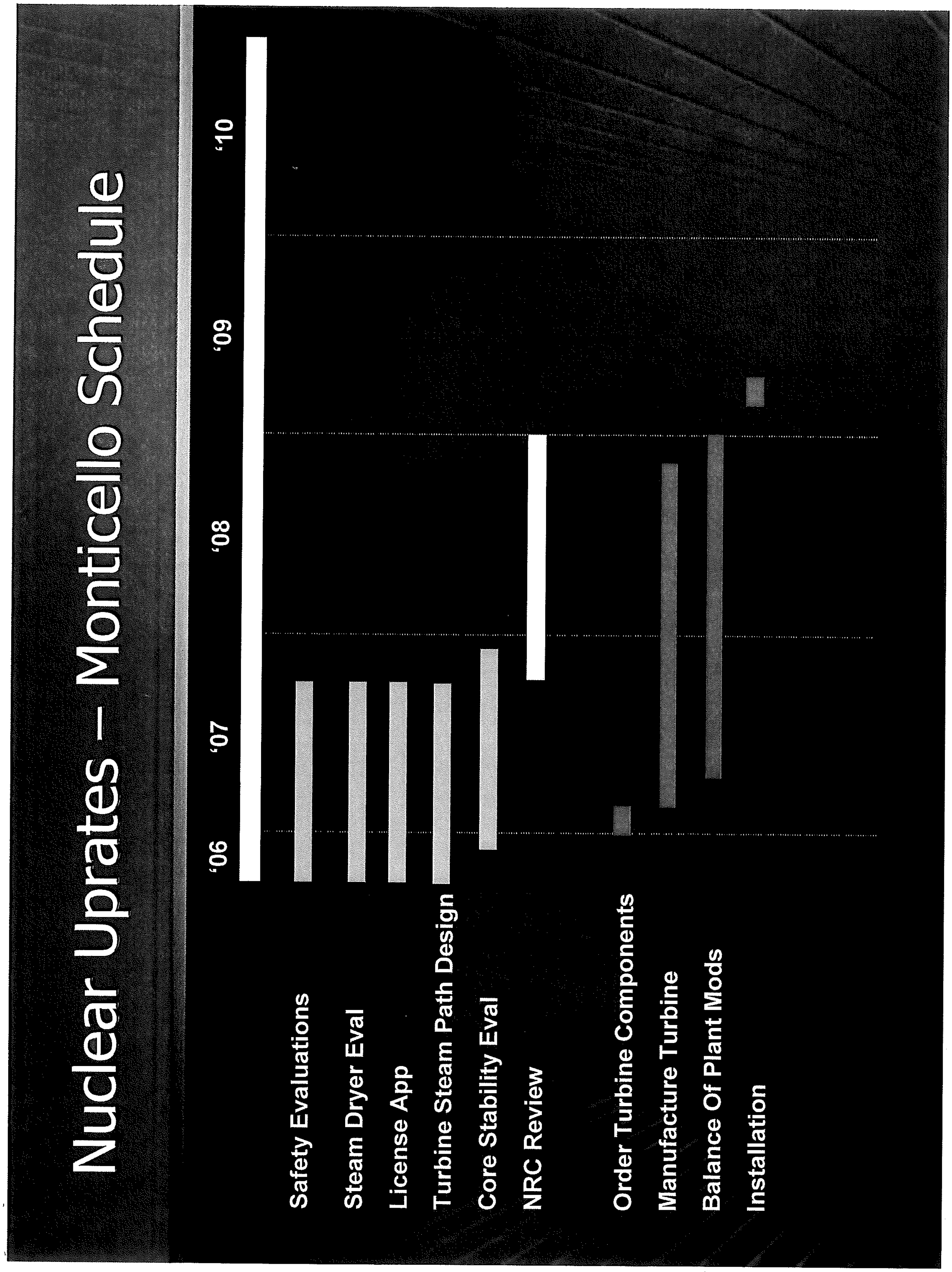
($M)	'06	'07	'08	'09	'10	'11	'12 – '15	Total
Monticello	$ 6.9	$ 8.3	$ 41.0	$ 13.8	$ 22.2	$ 17.4	$ 6.4	$ 116.0

[redacted]

(GE Cashflow Options)

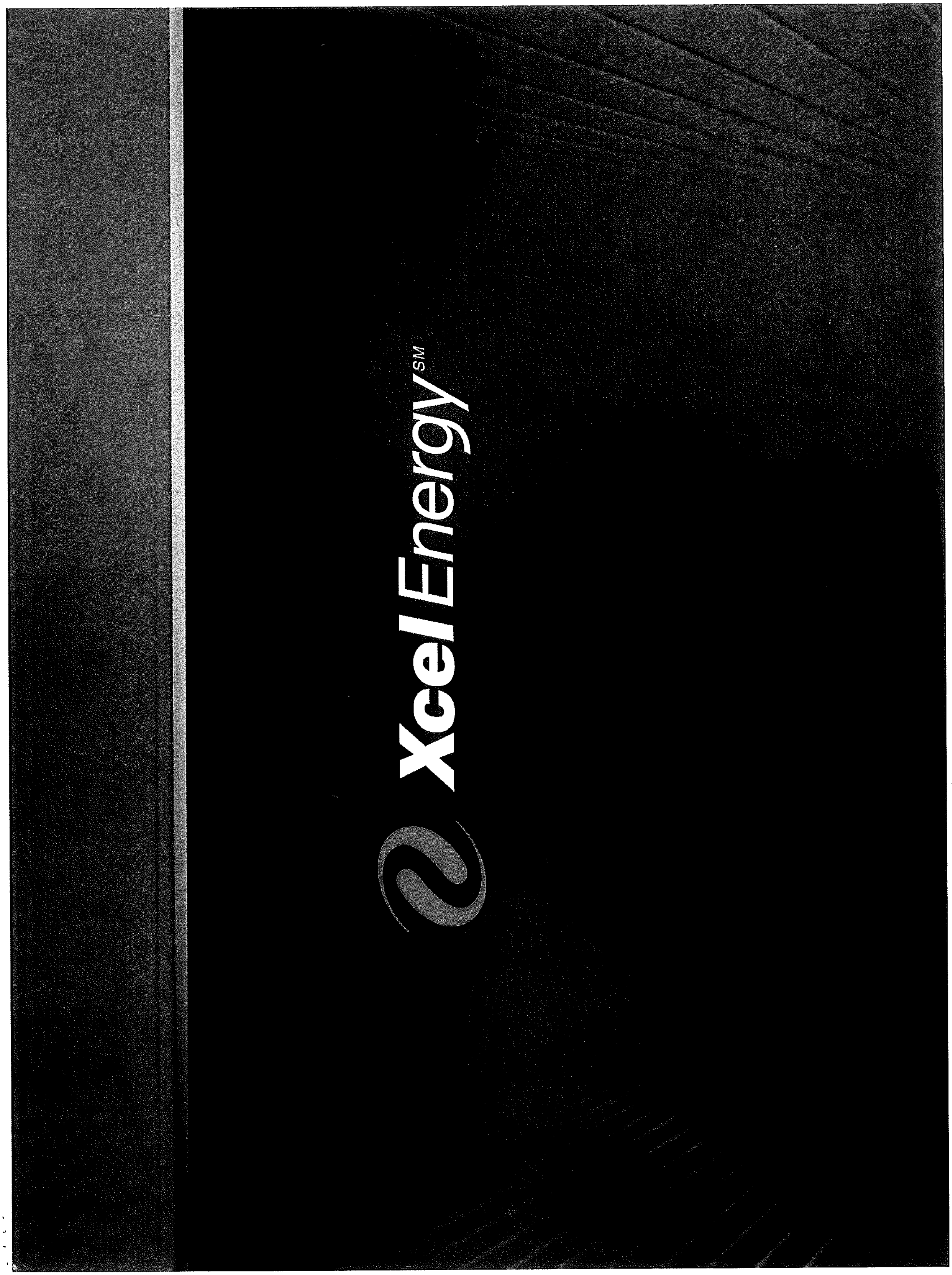
Option 1	$ 11.3	$ 7.4	$ 27.6	$ 10.9	$ 19.8	$ 16.9		$ 94.0
Option 2	$ 5.0	$ 13.8	$ 27.6	$ 10.8	$ 19.8	$ 16.9		$ 93.9
Option 4 Preferre	$ 5.0	$ 5.0	$ 37.1	$ 10.9	$ 19.8	$ 16.9		$ 94.7

Estimates are in '06 Dollars


Nuclear Uprates – Monticello Schedule
'06
'07
'08
'09
'10
Safety Evaluations
Steam Dryer Eval
License App
Turbine Steam Path Design
Core Stability Eval
NRC Review
Order Turbine Components
Manufacture Turbine
Balance Of Plant Mods
Installation

Next Steps

- Xcel Energy Management approval to proceed in 2006 with up to $7.1M
  - Complete negotiations with GE to begin project
  - Finalize project proposals and filing documents
  - Review final projects/contracts with Financial Council (October 2006)
  - Approval of full project by Xcel Board of Directors (Oct '06)


Xcel Energy[SM]

Mr. Richard C. Kelly
Page 7

	2007 Expenditures	Total Project Expenditures
III. ENERGY SUPPLY – NUCLEAR		

[redacted]

include life cycle management — $273.8

➢ **Monticello – Extended Power Uprate,** **$ 10.3** ~~**$ 135.8**~~ EPU & LCM (ONLY 2 COMPONENTS
This project is to increase plant output to approximately 120% of originally licensed capacity. In 1996, Monticello had a 6% uprate, with approximately 10% remaining power uprate potential. In June of 2006, the Minnesota PUC ordered Xcel to submit a Certificate of Need for a Monticello Uprate.

[redacted]

Application to the Minnesota Public Utilities Commission for a Certificate of Need to Establish an Independent Spent Fuel Storage Installation at the Monticello Generating Plant

Docket # E002/CN-05-123
January 18, 2005

Xcel Energy
NORTHERN STATES POWER

Chapter 5 Generation Alternatives to Continuing to Operate Monticello and Prairie Island: The No Action Alternative

5.1 The "No Action" Alternative

Our application asks for the dry spent fuel storage facility and containers necessary to operate Monticello to 2030. The need for dry on site storage is not eliminated if the plant does not operate beyond 2010. If a Certificate of Need were not granted, the Monticello plant would shut down by the end of 2010. In order to decommission the plant, spent fuel would have to be removed from the reactor and spent fuel pool. A dry storage facility utilizing 40 storage containers would be needed in order to fully decommission the plant. As part of the process of developing a decommissioning plan, Xcel Energy would have to apply to the Commission for a Certificate of Need for on site dry storage. In addition, the lost production capacity would have to be replaced with a coal or natural gas fueled base load power plant.

5.2 Demand Side Management

The demand for electricity in Xcel Energy's service territories in the Upper Midwest is growing at the rate of about 1.65 percent per year or roughly 900 gigawatt hours and 150 megawatts each year. Our estimates of demand and energy consumption take into account the conservation and demand management goals set by the Commission in 2001. Without those efforts, growth would be some 50 megawatts higher each year.

In our recent Resource Plan filing, additional analysis of conservation and load management measures was completed to determine if overall costs of Xcel Energy's power supply could be reduced. The analysis indicates that incremental increases in DSM goals to further slow the growth in electrical demand are cost justified. However the analysis also indicates that additional increments of DSM become uneconomical far before reaching the point that growth is eliminated. DSM can cost-effectively reduce the rate of growth in customer demand and energy requirements, but cannot feasibly go on to reduce demand and eliminate the need for the 600 megawatts of power and over 4 million megawatt hours of energy provided by Monticello. There are also market penetration issues regarding DSM that must be addressed for us to achieve even the higher DSM goals proposed in our pending Resource Plan.

Our discussion of DSM analysis is included in this application in the second portion of Appendix C.

5.3 Generation Alternatives

In this Chapter of our application we present the analysis of generation alternatives that leads us to conclude that Monticello and Prairie Island should continue to be part of the fleet of plants that supply power to Minnesota and surrounding states.

Throughout the '90s, Xcel Energy's Resource Plans have included an analysis of the role the Monticello and Prairie Island power plants play in meeting our customers' demand for electrical power. The two plants represent approximately 20 percent of the production capacity used to meet electrical demand and provide nearly 30 percent of the electricity our customers use. With uncertainty about the fate of spent nuclear fuel storage at Prairie Island and Monticello and the pending end of the original 40-year licenses to operate both plants, our Resource Plans have analyzed the economic and environmental impacts of continuing to operate the nuclear plants compared to replacing them.

Once more our analysis indicates that our power supply will be over a billion dollars more economical and have fewer air quality impacts if Monticello and Prairie Island continue to operate beyond their current licensed life.

This same analysis was presented in our Resource Plan filed with the Commission on November 1, 2004. Although both the Resource Plan proceeding and the Monticello Certificate of Need proceeding will be underway at the same time, we recommend to the Commission that issues related to whether to grant a Certificate of Need for Monticello--including a comparison to alternatives-- be addressed in the Certificate of Need proceeding. We believe this result is required by the 2003 Act that specifies that a request for additional storage beyond that authorized by the legislation be determined in a Need proceeding.

5.3.1 Analysis of Prairie Island, Monticello and the Alternatives

Xcel Energy uses the "Strategist" resource expansion model[1] to analyze various long-range electric supply-demand alternatives. Strategist:

- Develops the optimized selection of resources to meet need, given the input assumptions.
- Calculates the present value of revenue requirements ("PVRR") to measure the economic impacts of various planning scenarios.
- Calculates environmental impacts of the plan, using input externality values.

Strategist is useful as a planning tool in two ways. First, given a set of assumptions about the forecasted demand for electricity and the resources available to meet that demand, Strategist will optimize the operation of existing resources and add new resources to develop the expansion plan with the lowest PVRR. The model picks the resources to minimize overall cost of the plan.

[1] "Strategist" is a registered trademark of New Energy Associates, Inc. New Energy Associates developed and maintains the Strategist model.

Strategist is also used to examine alternatives. In this case, Strategist is "forced" to accept a particular resource or an entire expansion plan, and the resulting PVRRs can be compared to analyze the effects of different resource choices. Xcel Energy used this technique to examine the effects of a shutdown of our nuclear plants, and to compare various base load replacement options.

In our resource planning analysis we have tested variations around three nuclear power futures: First, one in which both Prairie Island and Monticello are relicensed to run another 20 years beyond their current licensed lives; second, one in which both Monticello and Prairie Island run only to the end of their current operating licenses; and third, one in which Monticello is shut down in 2010 and Prairie Island is relicensed. In the second and third scenarios, our analyses test the impact of replacement with gas combined cycle power plants and coal fueled power plants. We also test the impact of adding more wind-powered generation in combination with the gas-replacement scenario. In each case the Strategist model was run to simulate the operation of the system between 2004 and 2033. As explained in Section 5.2.3.4, we do not view the third scenario as a probable outcome, but we have shown it in order to help isolate the impacts of a decision on a Certificate of Need for Monticello.

The results of our analysis are shown in Table 5-1 and 5-2 on the next two pages:

Table 5-1
Nuclear Study Results – Prairie Island and Monticello Relicense Scenarios
2004 Resource Plan – Study Timeframe 2004 – 2033
PVRR in 2004 $000,000 (millions of dollars)

Case Description	Scenario	Strategist Economic Differences	Decommissioning Adjustments	Employee Retention Adjustment	Transmission Adjustment
Monti and PI License Renewal	Median Gas	0	0	0	0
	High Gas	665			
	Low Externalities	480			
	High Externalities	2,310			
Monticello '10 Prairie Island '13/'14 Coal Replacement	Median Gas	835	275	95-185	~100
	High Gas	1,685			
	Low Externalities	1,360			
	High Externalities	3,710			
Monticello '10 Prairie Island '13/'14 Gas Replacement	Median Gas	1,115			
	High Gas	2,150			
	Low Externalities	1,635			
	High Externalities	3,695			
Monticello '10 Prairie Island '13/'14 Gas/Wind Repl.acement	Median Gas	1,165			
	High Gas	2,190			
	Low Externalities	1,680			
	High Externalities	3,685			

Table 5-2

Nuclear Study Results – Prairie Island Relicense, Monticello Shutdown Scenarios

2004 Resource Plan – Study Timeframe 2004 – 2033

PVRR in 2004 $000,000 (millions of dollars)

Case Description	Scenario	Strategist Economic Differences	Decommissioning Adjustments	Employee Retention Adjustment	Transmission Adjustment
Monti and PI License Renewal	Median Gas	0	0	0	0
	High Gas	665			
	Low Externalities	480			
	High Externalities	2,310			
Monticello '10 Prairie Island '33/'34 Coal Replacement	Median Gas	395	105	45-90	
	High Gas	1,240			
	Low Externalities	895			
	High Externalities	3,015			
Monticello '10 Prairie Island '33/'34 Gas Replacement	Median Gas	560			
	High Gas	1,345			
	Low Externalities	1,055			
	High Externalities	2,985			
Monticello '10 Prairie Island '33/'34 Gas/Wind Replacement	Median Gas	610			
	High Gas	1,380			
	Low Externalities	1,105			
	High Externalities	3,005			

The PVRR savings associated with relicensing compared to not operating both plants beyond their license lives decreases somewhat from those shown in the past Resource Plans. This result is largely due to the fact that in Scenario 2, Prairie Island is now assumed to operate from 2007 through 2014 where in the last plan it operated only through 2007 in most of the scenarios.

Extending the life of Prairie island and Monticello continues to show significant benefits to air quality. On the nuclear side, there will be additional spent fuel storage casks associated with relicensing and very minute amounts of radiation exposure.

The incremental emissions compared to continuing to operate our nuclear power plants is shown on Table 5-3 on the next page:

Table 5-3 Nuclear Study – Prairie Island and Monticello Shutdown Scenarios 2004 Resource Plan – Study Timeframe 2004 – 2033 Emissions – Differences from License Renewal in 000's of Tons						
	NOx	PM10	CO2	SO2	VOC	CO
Prairie Island & Monticello Licenses Renewed 30, 33, 34	0	0	0	0	0	0
Prairie Island & Monticello Close end of License '10, 13, 14 Replace with Coal	94	5	259,080	127	4	179
Prairie Island & Monticello Close end of License '10, 13, 14 Replace with gas	51	8	181,367	58	4	79
Prairie Island & Monticello Close end of License '10, 13, 14 Replace with gas & wind	35	8	141,717	36	4	49
Monticello closes EOL Relicense PI Replace with coal	34	2	92,382	44	2	58
Monticello closes EOL Relicense PI Replace with gas	26	3	79,441	30	2	39
Monticello closes EOL Relicense PI Replace with gas & wind	22	3	69,163	26	2	35

5.3.2 Modeling Inputs

In order to run the production simulations, several input assumptions are provided to the model. In addition, some issues do not lend themselves well to computer simulation, in which case adjustments to the Strategist output are made. Below we describe some of the key variables we used to analyze nuclear power's role in our resource mix.

5.3.2.1 Capital Investments

In Section E.1 of Appendix E of our application we discuss the ongoing processes for identifying emerging aging issues, also known as life cycle management, that have been integral to the operation of the Monticello plant over the years. In Section E.2 of Appendix E of our application we discuss the NRC license renewal process. These discussions are provided to provide context for this section where we discuss the capital investments used in the Resource Plan analyses for Monticello and Prairie Island. As part of the operation and management of the plants, Xcel Energy routinely invests and upgrades systems so that the plant maintains safe and highly reliable operations. Xcel Energy invests an average of about $10 million dollars annually in the Monticello plant to keep systems operating well. Capital investments average $16.5 million annually at Prairie Island. In our analysis we have assumed these levels of capital investment will continue to be made in the plants.

In addition to the capital investments routinely made on an annual basis, larger capital investments are sometimes required. These larger capital investments can come about as a result of new or evolving regulatory requirements, operating experience at our plants or elsewhere in the industry, parts obsolescence or new technologies becoming available. These types of investments have been considered as part of the process leading to a decision to pursue license renewal. Individuals responsible for system operation at the plant utilize the types of inputs described above, identify and develop recommended large capital improvements that are reviewed, approved and prioritized to ensure continued safe and reliable operations. No major structural changes to the reactor or the storage pool will be needed.

5.3.2.1.1 Estimating and Cost Forecasting

While estimating and cost forecasting are not considered hard science, extending the operating period for a plant by 20 years has been authorized several times. In fact, at least 46 of the 104 operating reactors in the US have either received their renewed licenses or have submitted their applications. Another 29 have committed to the NRC to submit applications for license renewal in the near future. Those that have received NRC approval are aware of their additional maintenance and aging management commitments and have started to implement these activities to an extent where the costs have been incrementally added to their operating budgets. None of the applicants have identified any major capital expenses as a result of their aging assessments; the emphasis is on preventive and predictive maintenance, aging management and repair or replacement on the basis of attaining highest reliability at least cost. These results are in line with the early aging studies discussed above.

The Plant also relies on its historic operating experience over the last 30 years with respect to capital cost needs for major equipment overhauls or replacements. Most of the power plant equipment necessary to generate electricity is fairly equivalent to equipment operating in coal and hydroelectric power plants for 60, 70 and more years, including turbines, generators, cable, piping, valves, structures and many more. In short, the industry has learned how to maintain these plants in operating order and planning for the capital costs to do so.

Costs for new equipment, hardware, installation and service are typically provided by suppliers and vendors on a competitive bid basis and cost uncertainties are significantly reduced using fixed price proposals. Major projects are typically undertaken with the help of outside resources who have extensive experience in costing the equipment and work. Capital costs are well known for routine projects and are budgeted for accordingly.

For major power plant equipment, defined as those systems and components whose failure could affect plant safety functions or result in a loss of power production, extensive aging and life cycle studies have been performed by EPRI, the National Laboratories (Brookhaven, Argonne, Sandia) and various power plant owners groups to determine the long-term degradation, operational behavior and life expectancy. The studies resulted in identification of recommended mitigative and preventive actions, including timely replacement, such that for each major component an action plan is available and the cost of implementation can be forecasted. Typical generic assessments included plant cabling, main condenser, reactor vessel and internals, large breakers and motors, main generator and turbine, transformers, circulating water pumps and many more. The life cycle studies typically include a number of maintenance alternatives to determine the action plan with the highest reliability at the least cost.

The Plant also relies on the maintenance history and cost data from its sister plants and other plants managed by NMC and the boiling water reactor fleet at large. Equipment cost and labor costs, as well as time to repair and any outage impact are exchanged among plants and individual system engineers. This information is mostly used to calibrate plant specific estimates and forecasts.

For projects that are considered unique to the Plant, such as the costs for cable replacement, detailed cost estimates are prepared in-house with the help and input from vendors and consultants. These projects typically stretch over several years with a study phase, preparation phase and implementation phase. Specific capital cost forecast are spread accordingly over the years to smooth the impact on the annual budgets.

Lastly, there are regulatory driven costs that are incurred as a result of changes to the law that applies to the continued safe operation of all plants. The NRC creates the changes to the Federal Code and all plants have to implement these changes, independent of their operational life cycle. Because all plants must implement regulatory changes, the costs are not unique to Monticello.

At the Plant, the system engineers are the principal caretakers of the systems and components within. Included in this responsibility is the continued monitoring of industry and regulatory developments applicable to their assigned systems. The system engineer is the generator of improvement project requests based on the performance and condition of his/her system. Through access to industry information generated by EPRI, the NRC, INPO and other sources, the system engineer learns about new products, services and tools that can make the system better. When an opportunity is identified that may result in enhanced safety, improved economics or improved equipment reliability, a project proposal is generated that includes technical and economic justification. Cost data is provided based on internal estimates, historic costs, vendor proposals or consultant findings.

The Plant uses all the available industry resources to identify potential projects that may enhance Plant safety, performance and condition. Industry and Plant specific operating experience provides the bulk of the newly identified projects, because they are largely repetitive activities, such as rewinding the generator, replacing turbine rotors, re-tubing the condenser or replacing electrical breakers. The historic cost data from the last time the activity was performed is utilized and adjusted for inflation. The costs are then calibrated or supplemented with cost data provided by vendors to account for new materials, technology or equipment upgrades.

5.3.2.1.2 Monticello

Potential capital improvements included in the Resource Plan model include:

- Cable replacements;
- Implementing Improved Technical Specifications;
- Future possible security upgrades;
- New steam dryer;
- Electrical Breaker replacement;
- Repairs to cooling towers;
- Constructing or re-licensing ISFSI's;
- Repair or replacement of Main Steam and Feedwater piping;
- Upgrading to a next generation process computer and IT improvements;
- Replacing primary containment bellows;
- Replace/rebuild main control room instrumentation and control equipment due to obsolescence;
- Replace feedwater heaters;
- Replace generator rotor and rewind/refurbish generator stator;
- Replace static exciter; and,
- Complete under vessel cable replacement.

It should be noted that this is a representative list. Items may be added as new information becomes available. Likewise, repair or replacement of some items may not be necessary for safe and reliable plant operations. In total the projects listed represent some $135 million that have been included in the model over and above the routine capital of $10 million invested each year and is considered representative of the order of magnitude that Xcel Energy estimates is needed over the 20 years of additional operation.

5.3.2.1.2 Prairie Island

Xcel Energy has not yet performed the same detailed analysis of large capital investments for the Prairie Island plant. However, based on what is known about the plant, the work associated with Monticello, and information from a similar plant in the industry that has completed a license renewal application, we have incorporated estimates of future capital investments at Prairie Island into the analysis. These future large capital investments include the Unit 2 steam generators, reactor vessel head replacement for both units, and additional spent fuel storage costs. In total, inputs for large capital investments over and above the $16.5 million invested each year represent on the order of $450 million. Similar to the figure presented for Monticello, this is not a definitive list and items may be added or removed, but it is considered representative of the order of magnitude that Xcel Energy estimates is needed to invest over the 20 years of additional operation. In total, over $1 billion of investments in Monticello and Prairie Island have been included in the scenario in which both plants continue to operate.

Due to the costs associated with replacing the reactor vessel heads and the Unit 2 steam generator at Prairie Island, expanding the spent fuel storage capacity to accommodate spent fuel generated during the extended period of operation, and the costs associated with the relicensing process, a brief description of each of those is provided below.

5.3.2.1.3 Reactor Vessel Heads at Prairie Island

Cracking of the penetrations through the reactor vessel head in pressurized water reactors has been a growing concern in the nuclear industry. In light of the concern, the NRC issued a series of bulletins and orders requiring assessment and inspections by licensees who operate pressurized water reactors (PWRs). Prairie Island is a PWR and has complied fully with those requirements. The requirements specify an increasing scope and complexity of inspections for the reactor vessel head penetrations the longer they are in service. At some point the complexity of the inspections becomes so long and cumbersome that it becomes less expensive to replace the reactor vessel head than continuing to use and inspect them. A decision to replace the reactor vessel heads on both units at Prairie Island was made due to the increasing costs of inspections and the risks of repairs. The reactor vessel heads will be replaced during the 2005 and 2006 refueling outages. The reactor vessel head replacements are estimated to cost $46 million. This investment is included in both the continued operations scenario and the end of license scenarios.

5.3.2.1.4 Steam Generators at Prairie Island

Each unit at Prairie Island includes two steam generators. Both Prairie Island units are two-loop PWRs. A high-pressure water cycle transfers heat generated in the reactor core to steam generators, where steam is produced to drive the turbine generator. Steam generators are large vessels that separate high-pressure water circulating through the reactor from the steam cycle used to power turbine generators at the plant. In the steam generator vessels, heat is transferred from the primary reactor water cycle to the secondary steam cycle by passing water through and around 3,388 steel alloy tubes.

As we reported in past resource plans, through an aggressive program of inspection and maintenance the Prairie Island plant has been able to operate its steam generators longer than other plants of similar vintage. However, projections of steam generator tube degradation indicate that while plant safety can be maintained without compromise, the plant could become uneconomic as early as 2009 due to declining performance of the steam generators. In previous work we determined that replacing steam generators in unit 1 was cost justified even if the plant operated only to 2013. As a result, replacement was authorized. The two replacement steam generators were installed this fall.

Unit 2 steam generators have experienced less overall degradation than the Unit 1 steam generators. Therefore replacement cannot yet be justified. However, it will be necessary to replace the Unit 2 steam generators in order to keep the plant operating economically beyond the current license period. Our Strategist analysis includes steam generator replacement for Unit 2 in those scenarios in which Prairie Island operates beyond 2014. Steam generator

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☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy
Docket No.: E002/CI-13-754
Response To: Department of Commerce Information Request No. 038
Requestor: Nancy Campbell, Chris Shaw & Steve Rakow
Date Received: December 10, 2013

Question:

Reference: Table 4 on page 27 of Direct Testimony of O'Connor

Table 4 shows $104.4 million in Common Cost Allocations for the Monticello $664.9 million project. This appears to be a significant level of common costs (15.7%) that Xcel has assigned to this project, please provide a detailed description of the types of Xcel common costs that were assigned to this Monticello project and why they are appropriate.

Response:

As discussed further in our response to Information Request DOC-42, our practice for construction projects has consistently been to direct assign whatever charges are identifiable as related to a specific subproject activity and to allocate the remainder as common costs related to support all activities.

These common costs include design and engineering work, consulting work and other activities, such as radioactive protection, staffing, and scaffolding that were undertaken to support multiple subprojects. Generally, the amounts left in the common cost category were of a nature where it was difficult to determine which subproject(s) were specifically associated with the cost. The $104 million in remaining common costs was allocated on a pro rata basis among the subprojects upon completion. Weatherby Schedule 3, Section VI, describes the processes used for direct assignment of initial work order costs and the allocation of common costs.

We believe that a 15.7% level of common costs for a project of this magnitude and scope, with multiple subprojects, is reasonable. With more than 40 subprojects being

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included in the Monticello LCM/EPU Project, it is reasonable for 15.7% of the total costs to be either (a) related to the overall equipment systems being modified, without being tied to specific equipment or subproject elements, or (b) they support multiple (or all) subprojects.

Witness Weatherby's Schedule 4 provides a summary of the source transactions for the $104.4 million in common costs incurred for the Monticello LCM/EPU Project, as follows (in millions):

PASSPORT vendors	$ 88.6
Payroll (internal labor and benefits)	13.2
Overheads	2.1
Employee Expenses	0.4
Journal Entries (mainly accruals)	0.1
Total Common Costs for Project	$104.4

Attachment A to this response is a more detailed summary of the $104.4 million in common costs for the Project, with a listing of vendors by name and a description of the type of work they did, and the departments which charged employee labor. This Attachment also includes a description of why the cost item is included in common costs rather than being charged to a specific subproject.

We believe the standard for prudence of common costs should be whether they were reasonable and necessary for the overall project, regardless of whether they were directly charged to a specific subproject or allocated to all subprojects as a common cost. We further believe that this standard has been met, and is supported by the information we have provided and are providing with this response.

The detail of all Monticello LCM/EPU Project costs, including common costs, is provided in witness Weatherby's Schedule 2. As witness Weatherby has indicated to the Department, the Company reaffirms its commitment to assist the Department in obtaining the desired detail on common costs from the cost database in Schedule 2 upon request. Also, the Company can answer questions on the nature and appropriateness of any specific common cost incurred.

Trade Secret Data

Attachment A to this response includes confidential information considered to be "Non-Public," trade secret data as defined by Minn. Stat. § 13.37(1)(b). This data includes confidential vendor information that has independent economic value, from

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not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy maintains this information as trade secret.

Preparer:	Timothy J. O'Connor / Scott L. Weatherby
Title:	Chief Nuclear Officer / VP, Nuclear Finance & Business Planning
Department:	Nuclear Generation / Nuclear Finance & Business Planning
Telephone:	612-330-6521/ 612-330-7643
Date:	January 10, 2014

Monticello LCM /EPU Project
Summary of Common Costs Allocated Through 2013

Transactions Source	Total costs @ 8/31/13 after transfers, before allocations	Allocations per SLW Schedule 4 (rounded to Millions)	Source / Notes
Outside Vendor Spend			
Passport Vendors with > $300K in total spend	$ 79,313,129		See attached list by vendor and year
All other PassPort vendors (each <$300K in spend)	$ 6,795,512		See attached list by vendor and year
Subtotal - Passport vendors	$ 86,108,641		
Vendor Spend outside of Passport, including Matl issues	$ 2,370,807		See attached list by vendor and year (agrees with SLW Sched 3 App A-2)
Total Outside Vendor Spend Allocated as common	$ 88,479,448	88.6	Rounding difference of $0.1M
Payroll Costs (including Non-productive costs & benefit loadings)			
Incurred by Department (see summary attached)	$ 14,711,614		Summary attached: Agrees with Payroll items on SLW Sched 3 App A-2
Less payroll amounts transferred to licensing work order	$ (1,416,947)		Determined from review of detailed transfer activity
Total Payroll Costs Allocated as common costs	$ 13,294,667	13.2	
Overheads	$ 2,066,436	2.1	See summary attached (by type and year)
Employee Expenses	$ 379,028	0.4	See summary attached (by type and year)
Accruals - net (mainly unpaid amounts accrued at 8/31/13)	$ 144,585	0.1	Per SLW Schedule 3 Appendix A-2
TOTAL COMMON COSTS - Allocated to child work orders	$ 104,364,163	104.3	

Monticello LCM/EPU Project
Common Workorder Invoices Paid
Top 39 PASSPORT Vendors (spend all yrs > $300K)

Through August 31, 2013 6,118,412 9,608,846

Explanations for Common WO Invoices Paid - Top 39 Vendors, w/ total spend all yrs > $300K

Sum of Amount Code	Vendor Name	Year 2006	2007	2008	2009	2010	2011	2012	2013	Grand Total (Gross Costs Without Allocations or Transfers Removed)	Transfers Out - General Electric	Transfers Out - Licensing Costs	Transfers Out - RWIP	Net Common Costs after removing Allocations and Transfers 2006-2013	Net Common Costs after removing Allocations and Transfers 2006-2013	Rank	Explanation of Vendor Costs	Basis/Reason for Treating as a Common Cost vs. Direct Assigning It
	[BEGIN TRADE SECRET																	
PASSPORT AP / CM				886,069	2,576,643	5,673,785	6,796,631			15,933,127				15,933,127	15,933,127	1	Implementation contractor's "core staff" generally consisting of: Project Manager, Si Superintendent, Lead Mechanical Supervisor, Lead Electrical Supervisor, Civil Supervis Field Engineers, Work Order Control clerks, Project Controls, Scheduler, Project Assistant. Performed work order task planning for 2009 & 2011 outages and provided craft supervision.	Staff Augmentation support provided across all projects - At the time, the Project Manager did not feel it practical to track and assign costs to individual projects.
				50,139,300	(7,475,409)	24,146,391	6,945,854	266,759		74,022,895	(48,468,233)	(25,287,903)		266,759	266,759	2A	Primarily specialized EPU engineering analysis.	Predominately milestone payments made to vendor and not discernible to speci projects.
		5,631,200	5,280,000							10,911,200				10,911,200	10,911,200	2B	Primarily specialized EPU engineering analysis.	Predominately early milestone payments made to vendor and not related to speci projects.
				4,577,593	5,578,443	807,698	394,176	65,697	143,268	11,566,875		(226,974)		11,339,901	11,339,901	3	Provided pre-outage planning and project support primarily for the 2009 outage.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				789,862	1,241,481	1,711,035	2,033,692	584,068	791,434	7,151,572		(1,254,541)		5,897,031	5,897,031	4	Staff augmentation support including management, field supervision, specialists an administration.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
		487,212	4,328,846							4,816,059				4,816,059	4,816,059	5	See explanations for vendors with 2008 spend shaded in yellow (NMC spend in 2006-(was for those vendors, who were used in 2006-07 similar to 2008).	See explanations for vendors with 2008 spend shaded in yellow (NMC spend in 2006-(was for those vendors, who were used in 2006-07 similar to 2008).
				2,466,616	2,783,036	4,266,326	2,627,112	238,094	14,538	12,395,723		(8,054,758)		4,340,965	4,340,965	6	Primarily project management core team support. Staff augmentation for proje management; instrumentaiton & control specialists; information technology specialists;	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
						280,736	2,361,812	(0)		2,642,548				2,642,548	2,642,548	7	Radiation protection staff augmentation support primarily during the 2011 outage.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
						105,710	929,822	133,453	225,411	1,394,396				1,394,396	1,394,396	8	Construction oversight & coordination support.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				12,616	367,564	151,554	723,102	10,906	(15,456)	1,250,287				1,250,287	1,250,287	9	Provided quality control/oversight inspection services.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				623,059	573,443	17,393				1,213,895				1,213,895	1,213,895	10	Specialized engineering support primarily during the 2009 outage.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
						227,464	403,386	389,203	180,380	1,200,433				1,200,433	1,200,433	11	Lease of warehouse for material storage and pre-assembly space.	This was a multi use facility supporting many projects, not practical to direct assig costs to individual projects
					155,018	212,269	241,893	257,816	324,889	1,191,886				1,191,886	1,191,886	12	Staff augmentation specialists including corrective actions coordination, project director fire protection.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
							968,073	148,176	50,328	1,166,577				1,166,577	1,166,577	13	Mid-cycle outage modification implementation planning support. Staff Augmentatior mobilization of initial construction team to perform plant walkdowns and implementation assesments of potential mid-cycle and future outage work.	Staff Augmentation support provided across all projects - At the time, the Project Manager did not feel it practical to track and assign costs to individual projects.
							1,151,400			1,151,400				1,151,400	1,151,400	14	Provided fuel engineering analysis related to uprat	Related to overall EPU analysis. Project Manager assigned to commc
				105,210	358,765	360,381	659,199	18,211	750	1,502,516		(411,630)		1,090,886	1,090,886	15	Staff augmentation specialists including engineering, procedures, CAP assessment startup testing.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				869,718	707,404	839,896	503,892			2,920,911		(1,835,061)		1,085,850	1,085,850	16	Provided various engineering analysis and support services for the 2009 & 2011 outages	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				1,018,597	928,728	581,266	251,626			2,780,217		(1,802,374)		977,843	977,843	17	Provided engineering staff augmentation support for the 2009 & 2011 outages.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
						214,553	347,525	115,643	(1,300)	676,421				676,421	676,421	18	Provided training coordination requirements and support.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				109,806	78,747	94,778	181,572	86,386	91,550	642,840				642,840	642,840	19	Lease/rental of office trailers and furniture.	At the time, the Project Manager did not feel it practical to track and assign costs individual projects.
					23,858	28,355	257,153	86,990	222,678	619,033				619,033	619,033	20	Rental of scaffolding materials.	At the time, the Project Manager did not feel it practical to track and assign costs individual projects.
					2,340	33,902	174,521	101,155	300,926	612,845				612,845	612,845	21	Rental of construction equipment.	At the time, the Project Manager did not feel it practical to track and assign costs individual projects.
							245,334	240,923	118,587	604,844				604,844	604,844	22	Specialist for training lesson plan development.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				281,644	269,354	636,972	638,904	72,379		1,899,253		(1,312,613)		586,640	586,640	23	Staff augmentation specialists including engineering and welding inspection.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				66,579	125,686	150,680	342,029	82,487	162,396	929,857		(347,096)		582,761	582,761	24	Primarily administration staff augmentation support.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
							582,618			582,618				582,618	582,618	25	Construction planning & scheduling support during the 2011 outage.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				115,912	97,508	152,462	447,446	23,855	4,257	841,441		(283,184)		558,257	558,257	26	Engineering drafting/field coordination support.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
						112,932	75,348	205,969	137,313	531,562				531,562	531,562	27	Simulator training upgrades.	At the time, the Project Manager did not feel it practical to track and assign costs individual projects.
					23,101	3,164	477,524	(4,470)	677	499,995				499,995	499,995	28	Tool and metal decontamination services.	At the time, the Project Manager did not feel it practical to track and assign costs individual projects.
					12,500			3,700	483,266	499,466				499,466	499,466	29	Security support services.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
						104,311	219,930	139,093	34,610	497,944				497,944	497,944	30	Developed operations training lesson plans.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				433,381	288,218	204,285				925,884		(441,525)		484,359	484,359	33	Specialized engineering analysis.	Early analysis of original steam dryer to support decision on modify or replace. Project Manager assigned to "common" since no work order existed for new steam dryer project.
				127,153	279,527	47,846	2,642	1,528		458,697				458,697	458,697	31	Provided various engineering analysis and support services.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				105,173	459,610	367,870	174,726		50,025	1,157,404		(715,558)		441,846	441,846	32	Staff augmentation specialists including engineering and project management.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				289,887	148,646	19,886				458,419		(19,038)		439,381	439,381	33	Performed various engineering calculation updates.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
							53,520	374,534	(29,477)	398,577				398,577	398,577	34	Lease of in processing facility.	At the time, the Project Manager did not feel it practical to track and assign costs individual projects.
				37,348	79,640	1,307	2,383	231,662	27,435	379,776				379,776	379,776	35	Provided legal staff augmentation services	Professional services related to multiple vendor/contract issue
					202,500	148,140	2,160	14,310	6,390	373,500				373,500	373,500	36	Specialist for procedure writing.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				63,515	36,181	138,521	2,866		109,702	350,785				350,785	350,785	37	Provided craft supervision and coordination.	Staff Augmentation support provided across all projects - At the time, the Proje Manager did not feel it practical to track and assign costs to individual projects.
				2,726	9,573	30,631	110,256	83,855	78,778	315,821				315,821	315,821	38	Rental of construction equipment.	At the time, the Project Manager did not feel it practical to track and assign costs individual projects.
					1,881	49,817	103,745	91,670	57,008	304,120				304,120	304,120	39	Rental of construction equipment.	At the time, the Project Manager did not feel it practical to track and assign costs individual projects.
	END TRADE SECRET]																	
	Total - all vendors with spend over $300K for all years	6,118,412	9,608,846	63,121,766	9,933,987	41,922,317	31,433,873	4,064,051	3,570,365	169,773,617	(48,468,233)	(41,992,255)	-	79,313,129	79,313,129			
	Vendors with spend under $300k for all years	-	-	1,868,529	2,353,615	2,048,716	3,034,269	813,531	892,845	11,011,506	-	(4,215,994)	-	6,795,512	6,795,512			
PASSPORT AP / CM Total - All Vendors, All Years		6,118,412	9,608,846	64,990,295	12,287,602	43,971,033	34,468,142	4,877,582	4,463,210	180,785,123	(48,468,233)	(46,208,249)	-	86,108,641	86,108,641			
	% of Total covered by top 39 (>$300k spend on all years)	100.0%	100.0%	97.1%	80.8%	95.3%	91.2%	83.3%	80.0%	93.9%	100.0%	90.9%		92.1%	92.1%			
	Portion of Vendor spend less than $300K for all years	0.0%	0.0%	2.9%	19.2%	4.7%	8.8%	16.7%	20.0%	6.1%	0.0%	9.1%		7.9%	7.9%			

Monticello LCM/ EPU Project

Common Workorder PASSPORT Vendor Invoices Paid (Before Transfers or Allocations Out) - with total spend less than $300k

Through August 31, 2013

Sum of Amount			Year												
CodeSource	CodeDesc	VName	2006	2007	2008	2009	2010	2011	2012	2013	Grand Total (Gross Costs Without Allocations or Transfers Removed)	Transfers Out - General Electric	Transfers Out - Licensing Costs	Transfers Out - RWIP	Net Costs after removing Allocations and Transfers
		[BEGIN TRADE SECRET													
PASSPORT	AP / CM				$ 256,413	$ 1,045,925	$ 333,651	$ 63,067			$ 1,699,056		$ (1,699,056)		$ (0)
					$ 366,962	$ 304,769	$ 54,630				$ 726,360		$ (603,016)		$ 123,344
						$ 98,280	$ 268,670	$ 227,080			$ 594,030		$ (572,320)		$ 21,710
					$ 125,733	$ 32,288	$ 186,473	$ -			$ 344,494		$ (312,844)		$ 31,650
							$ 91,619	$ 197,879			$ 289,498		$ (139,741)		$ 149,757
									$ 245,026	$ 41,852	$ 286,878				$ 286,878
					$ 38,450	$ 11,850	$ 130,819	$ 104,535			$ 285,655				$ 285,655
					$ 161,900	$ 56,187	$ 31,505				$ 249,592		$ (249,592)		$ 0
									$ 84,042	$ 164,756	$ 248,798				$ 248,798
						$ 39,623	$ 79,630	$ 77,347	$ 14,171	$ 18,389	$ 229,161				$ 229,161
						$ 1,472	$ 140,620	$ 86,584			$ 228,676				$ 228,676
								$ 226,190			$ 226,190				$ 226,190
							$ 48,517	$ 151,983			$ 200,500				$ 200,500
					$ 200,000						$ 200,000		$ (200,000)		$ -
					$ 15,035	$ 36,713	$ 39,551	$ 38,924	$ 35,680	$ 19,831	$ 185,734				$ 185,734
					$ 161,800	$ 23,920					$ 185,720		$ (185,720)		$ -
					$ 55,396	$ 64,778		$ 47,999			$ 168,173				$ 168,173
					$ 84,022	$ 68,714	$ 5,786				$ 158,522		$ (120,034)		$ 38,488
								$ 156,698			$ 156,698				$ 156,698
								$ 156,618			$ 156,618				$ 156,618
								$ 34,229	$ 69,566	$ 47,268	$ 151,063				$ 151,063
									$ 27,940	$ 117,366	$ 145,306				$ 145,306
							$ 4,000	$ 140,504			$ 144,504				$ 144,504
								$ 142,750			$ 142,750				$ 142,750
						$ 43,616	$ 33,228	$ 16,274	$ 11,112	$ 22,109	$ 126,339				$ 126,339
						$ -		$ 31,400	$ 93,540		$ 124,940				$ 124,940
								$ 28,590	$ 78,562	$ 6,722	$ 113,874				$ 113,874
								$ 54,864	$ 24,873	$ 31,772	$ 111,508				$ 111,508
							$ 40,372	$ 65,429			$ 105,801				$ 105,801
								$ 60,587		$ 40,459	$ 101,046				$ 101,046
							$ 2,546	$ 34,939	$ 23,329	$ 36,253	$ 97,068				$ 97,068
						$ 14,862	$ 8,149	$ 24,616	$ 22,059	$ 22,391	$ 92,076				$ 92,076
							$ 91,800				$ 91,800				$ 91,800
							$ 35,680	$ 52,026			$ 87,706				$ 87,706
					$ 40,142	$ 40,145	$ 6,905				$ 87,192		$ (87,192)		$ 0
		END TRADE SECRET]													

Monticello LCM/ EPU Project
Common Workorder PASSPORT Vendor Invoices Paid (Before Transfers or Allocations Out) - with total spend less than $300k

Through August 31, 2013

Sum of Amount			Year								Gross Costs Without Allocations or Transfers Removed	Transfers Out - General Electric	Transfers Out - Licensing Costs	Transfers Out - RWIP	Net Costs after removing Allocations and Transfers
CodeSource	CodeDesc	VName	2006	2007	2008	2009	2010	2011	2012	2013	Grand Total				
		[BEGIN TRADE SECRET													
								$ 81,973			$ 81,973				$ 81,973
						$ 77,350					$ 77,350				$ 77,350
							$ 5,071	$ 52,005	$ 2,794	$ 16,241	$ 76,110				$ 76,110
								$ 74,600			$ 74,600				$ 74,600
							$ 965	$ 3,098	$ 1,213	$ 68,295	$ 73,570				$ 73,570
						$ 72,696					$ 72,696				$ 72,696
					$ -		$ 65,127	$ 700			$ 65,827				$ 65,827
					$ 793	$ 15,140	$ 2,127	$ 20,480	$ 4,956	$ 20,798	$ 64,295				$ 64,295
						$ 57,275		$ 336	$ 2,306	$ -	$ 59,916				$ 59,916
								$ 5,709	$ 8,162	$ 44,335	$ 58,205				$ 58,205
						$ 15,863	$ 19,958	$ 21,394			$ 57,214				$ 57,214
						$ 13,164	$ 1,749	$ 18,233	$ 5,053	$ 15,216	$ 53,415				$ 53,415
					$ 66,620	$ (21,000)	$ -	$ 5,000			$ 50,620				$ 50,620
							$ 41,384	$ 8,800			$ 50,184				$ 50,184
								$ 49,833			$ 49,833				$ 49,833
						$ 46,282					$ 46,282				$ 46,282
										$ 46,245	$ 46,245				$ 46,245
								$ 43,062	$ 0		$ 43,062				$ 43,062
						$ 39,600					$ 39,600				$ 39,600
							$ 14,960	$ 18,169	$ 5,000		$ 38,129		$ (33,129)		$ 5,000
						$ 4,579	$ 5,647	$ 10,535	$ 3,639	$ 12,933	$ 37,332				$ 37,332
						$ 32,401					$ 32,401				$ 32,401
								$ 3,425	$ 12,865	$ 12,922	$ 29,212				$ 29,212
								$ 28,506			$ 28,506				$ 28,506
					$ 26,703	$ (725)					$ 25,978				$ 25,978
								$ 25,854			$ 25,854				$ 25,854
								$ 2,607	$ 14,285	$ 8,294	$ 25,186				$ 25,186
							$ 25,180			$ (0)	$ 25,180				$ 25,180
						$ -		$ 25,000			$ 25,000				$ 25,000
					$ 25,000						$ 25,000				$ 25,000
						$ 24,472					$ 24,472				$ 24,472
					$ 22,917						$ 22,917				$ 22,917
							$ 21,881				$ 21,881				$ 21,881
								$ 17,472			$ 17,472				$ 17,472
										$ 16,837	$ 16,837				$ 16,837
		END TRADE SECRET]													

Monticello LCM/ EPU Project
Common Workorder PASSPORT Vendor Invoices Paid (Before Transfers or Allocations Out) - with total spend less than $300k

Through August 31, 2013

Sum of Amount			Year												
CodeSource	CodeDesc	VName	2006	2007	2008	2009	2010	2011	2012	2013	Grand Total / Gross Costs Without Allocations or Transfers Removed	Transfers Out - General Electric	Transfers Out - Licensing Costs	Transfers Out - RWIP	Net Costs after removing Allocations and Transfers
		[BEGIN TRADE SECRET													
						$ 16,444					$ 16,444				$ 16,444
								$ 21,134	$ (5,548)		$ 15,586				$ 15,586
					$ 13,552						$ 13,552				$ 13,552
						$ 10,682		$ 161	$ 547	$ 1,341	$ 12,731				$ 12,731
							$ 11,965				$ 11,965				$ 11,965
						$ 11,050					$ 11,050				$ 11,050
						$ 32	$ 17	$ 9,358		$ 1,105	$ 10,512				$ 10,512
							$ 6,478	$ 547	$ 2,901		$ 9,926				$ 9,926
						$ 3,459				$ 6,216	$ 9,675				$ 9,675
							$ 434	$ 9,116			$ 9,550				$ 9,550
								$ 2,829	$ 1,309	$ 5,330	$ 9,467				$ 9,467
									$ 8,902		$ 8,902				$ 8,902
							$ 1,616	$ 6,776			$ 8,392				$ 8,392
					$ 8,350						$ 8,350		$ (8,350)		$ -
									$ 7,575		$ 7,575				$ 7,575
					$ 7,535						$ 7,535				$ 7,535
								$ 715		$ 6,733	$ 7,449				$ 7,449
							$ 6,037	$ 828			$ 6,865				$ 6,865
								$ 6,749			$ 6,749				$ 6,749
										$ 6,325	$ 6,325				$ 6,325
						$ 653	$ 340	$ 585		$ 4,208	$ 5,785				$ 5,785
							$ 629	$ 3,909	$ 1,210		$ 5,748				$ 5,748
						$ -		$ 5,689	$ -	$ -	$ 5,689				$ 5,689
										$ 5,668	$ 5,668				$ 5,668
						$ 5,000				$ -	$ 5,000		$ (5,000)		$ -
						$ 1	$ 4,985		$ 8		$ 4,993				$ 4,993
								$ 4,862			$ 4,862				$ 4,862
							$ 340	$ 2,959	$ 108	$ 1,416	$ 4,824				$ 4,824
							$ 1,597			$ 3,136	$ 4,733				$ 4,733
							$ 1,405	$ 2,108	$ 1,194		$ 4,707				$ 4,707
							$ 4,518			$ 16	$ 4,534				$ 4,534
						$ 775		$ 820		$ 2,856	$ 4,451				$ 4,451
							$ 1,679	$ 12	$ 413	$ 2,147	$ 4,251				$ 4,251
								$ 3,792			$ 3,792				$ 3,792
						$ 3,722		$ (0)			$ 3,722				$ 3,722
		END TRADE SECRET]													

Monticello LCM/ EPU Project

Common Workorder PASSPORT Vendor Invoices Paid (Before Transfers or Allocations Out) - with total spend less than $300k

Through August 31, 2013

Sum of Amount			Year												
CodeSource	CodeDesc	VName	2006	2007	2008	2009	2010	2011	2012	2013	Grand Total (Gross Costs Without Allocations or Transfers Removed)	Transfers Out - General Electric	Transfers Out - Licensing Costs	Transfers Out - RWIP	Net Costs after removing Allocations and Transfers
		[BEGIN TRADE SECRET													
									$ 3,645	$ -	$ 3,645				$ 3,645
							$ 3,555	$ 573	$ (573)	$ -	$ 3,555				$ 3,555
							$ 146	$ 844		$ 2,552	$ 3,542				$ 3,542
						$ 0		$ 3,281			$ 3,281				$ 3,281
						$ 2,865					$ 2,865				$ 2,865
						$ 2,818					$ 2,818				$ 2,818
						$ 2,400					$ 2,400				$ 2,400
						$ 1,936				$ 433	$ 2,369				$ 2,369
					$ 729		$ 1,111	$ 380			$ 2,221				$ 2,221
									$ 1,072	$ 1,082	$ 2,153				$ 2,153
							$ 5	$ 1,857			$ 1,862				$ 1,862
								$ 650		$ 1,206	$ 1,856				$ 1,856
							$ 530	$ 1,277			$ 1,807				$ 1,807
					$ 1,492	$ 270					$ 1,762				$ 1,762
					$ 1,600						$ 1,600				$ 1,600
					$ 1,558						$ 1,558				$ 1,558
					$ 618	$ 5	$ 828				$ 1,452				$ 1,452
						$ 19	$ 98	$ 688		$ 633	$ 1,438				$ 1,438
										$ 1,395	$ 1,395				$ 1,395
							$ 1,388				$ 1,388				$ 1,388
							$ 1,223				$ 1,223				$ 1,223
						$ 408	$ 12	$ 571		$ 19	$ 1,009				$ 1,009
							$ 942				$ 942				$ 942
						$ 275	$ 19		$ 414	$ 213	$ 920				$ 920
						$ 374	$ 14	$ 154		$ 325	$ 868				$ 868
					$ 736						$ 736				$ 736
							$ 732				$ 732				$ 732
						$ 8		$ 76		$ 582	$ 667				$ 667
							$ 661				$ 661				$ 661
							$ 661				$ 661				$ 661
							$ 205	$ 373			$ 578				$ 578
						$ 9	$ 8	$ 46		$ 478	$ 541				$ 541
						$ 533					$ 533				$ 533
						$ 500					$ 500				$ 500
						$ 500					$ 500				$ 500
		END TRADE SECRET]													

Monticello LCM/ EPU Project
Common Workorder PASSPORT Vendor Invoices Paid (Before Transfers or Allocations Out) - with total spend less than $300k

Through August 31, 2013

Sum of Amount			Year												
CodeSource	CodeDesc	VName	2006	2007	2008	2009	2010	2011	2012	2013	Grand Total (Gross Costs Without Allocations or Transfers Removed)	Transfers Out - General Electric	Transfers Out - Licensing Costs	Transfers Out - RWIP	Net Costs after removing Allocations and Transfers
		[BEGIN TRADE SECRET													
						$ 184				$ 290	$ 474				$ 474
						$ 4		$ 442			$ 446				$ 446
						$ 429					$ 429				$ 429
								$ 428			$ 428				$ 428
					$ 108		$ 305				$ 414				$ 414
							$ 138	$ 4		$ 248	$ 389				$ 389
							$ 33	$ 321			$ 355				$ 355
						$ 327					$ 327				$ 327
							$ 72			$ 242	$ 314				$ 314
						$ 270	$ 13	$ 6			$ 288				$ 288
										$ 249	$ 249				$ 249
							$ 240				$ 240				$ 240
								$ 240			$ 240				$ 240
								$ 208		$ 24	$ 232				$ 232
					$ 213						$ 213				$ 213
								$ 204			$ 204				$ 204
							$ 201				$ 201				$ 201
						$ 200					$ 200				$ 200
								$ 179		$ 13	$ 192				$ 192
							$ 61			$ 131	$ 192				$ 192
								$ 35		$ 154	$ 189				$ 189
									$ 175		$ 175				$ 175
						$ 168					$ 168				$ 168
						$ 132		$ 8		$ 11	$ 151				$ 151
						$ 151					$ 151				$ 151
							$ 123				$ 123				$ 123
						$ 123					$ 123				$ 123
					$ 101						$ 101				$ 101
							$ 98				$ 98				$ 98
									$ 14	$ 83	$ 98				$ 98
										$ 97	$ 97				$ 97
								$ 96			$ 96				$ 96
								$ 76			$ 76				$ 76
							$ 20	$ 41			$ 61				$ 61
								$ 51			$ 51				$ 51
		END TRADE SECRET]													

Monticello LCM/ EPU Project

Common Workorder PASSPORT Vendor Invoices Paid (Before Transfers or Allocations Out) - with total spend less than $300k

Through August 31, 2013

Sum of Amount			Year												
CodeSource	CodeDesc	VName	2006	2007	2008	2009	2010	2011	2012	2013	Grand Total **Gross Costs Without Allocations or Transfers Removed**	**Transfers Out - General Electric**	**Transfers Out - Licensing Costs**	**Transfers Out - RWIP**	**Net Costs after removing Allocations and Transfers**
		[BEGIN TRADE SECRET													
						$ 51					$ 51				$ 51
								$ 38			$ 38				$ 38
								$ 27			$ 27				$ 27
						$ 27					$ 27				$ 27
								$ 22			$ 22				$ 22
								$ 22			$ 22				$ 22
							$ 15				$ 15				$ 15
						$ 9		$ 2			$ 11				$ 11
								$ 6			$ 6				$ 6
							$ 0	$ 5			$ 5				$ 5
								$ 4			$ 4				$ 4
								$ 1			$ 1				$ 1
								$ 2	$ (5)	$ 3	$ 0				$ 0
								$ (947)			$ (947)				$ (947)
					$ 184,048	$ 26,565	$ 155,017	$ 201,127		$ 4,602	$ 571,359				$ 571,359
		END TRADE SECRET]													
Total vendor spend less than $300K for all years combined			$ -	$ -	$ 1,684,481	$ 2,327,049	$ 1,893,700	$ 2,833,143	$ 813,531	$ 888,243	$11,011,506	$ -	$ (4,215,994)	$ -	$ 6,795,512

Monticello LCM/ EPU Project
Common Workorder Outside Vendor Costs - Issued Materials (IM) and Purchase Orders (PO) Paid Outside of PASSPORT
(2013 Costs Through August 31)

Sum of Amount			Year						
Code Source	Code Desc	Vendor Name	2008	2009	2010	2011	2012	2013	Grand Total
PASSPORT	IM / PO	**[BEGIN TRADE SECRET**							
			$ (26,197)	$ 229,303	$ 159,224	$ 120,913	$ 20,302	$ 484,867	$ 988,412
				$ 184,651	$ 570	$ 9,030	$ 1,135	$ 22,824	$ 218,210
								$ 185,146	$ 185,146
			$ 31,779	$ 73,442	$ 182				$ 105,404
				$ 53,215				$ 46,848	$ 100,062
				$ 69,220	$ 4,386	$ 1,581		$ 8,878	$ 84,064
						$ 84,042			$ 84,042
					$ 20,440	$ 30,660	$ 17,370		$ 68,470
				$ 11,919		$ 12,255		$ 41,656	$ 65,830
					$ 28,617			$ 26,225	$ 54,842
				$ 44,080					$ 44,080
				$ 6,081	$ 1,396	$ 7,620		$ 23,654	$ 38,750
				$ 5,098	$ 6,424	$ 1,090		$ 17,875	$ 30,487
						$ 30,205			$ 30,205
				$ 25,990					$ 25,990
			$ 23,638						$ 23,638
				$ 287	$ 1,427	$ 10,002		$ 9,349	$ 21,066
				$ 20,848					$ 20,848
					$ 20,195				$ 20,195
								$ 16,017	$ 16,017
			$ 9,508	$ 4,672					$ 14,180
					$ 14,850		$ (1,150)		$ 13,700
			$ 11,222		$ 2,084				$ 13,305
					$ 10,407				$ 10,407
			$ 3,311	$ 2,348				$ 3,095	$ 8,753
					$ 8,598	$ 121			$ 8,719
				$ 8,558					$ 8,558
					$ 2,983	$ 5,423			$ 8,406
			$ 1,887		$ 2,003	$ 53		$ 3,605	$ 7,548
				$ 4,754					$ 4,754
					$ 1,041			$ 3,526	$ 4,567
						$ 3,492			$ 3,492
					$ 1,440	$ 1,152	$ 864		$ 3,456
					$ 3,017				$ 3,017
					$ 888			$ 1,905	$ 2,793
					$ 2,070				$ 2,070
					$ 2,028				$ 2,028
				$ 2,012					$ 2,012
						$ 2,000			$ 2,000
				$ 1,606		$ 13		$ 161	$ 1,779
					$ 1,730				$ 1,730
								$ 1,406	$ 1,406
						$ 1,350			$ 1,350
						$ 1,000			$ 1,000
						$ 399			$ 399
						$ 200			$ 200
				$ 138					$ 138
					$ 115	$ (0)			$ 115
								$ 51	$ 51
						$ 26		$ 17	$ 43
						$ 20			$ 20
						$ 18			$ 18
								$ 0	$ 0
			$ 1,633	$ -	$ 2,412	$ 8,370	$ -	$ 619	$ 13,034
		END TRADE SECRET]							
	IM / PO Total		$ 56,781	$ 748,222	$ 298,525	$ 331,035	$ 38,521	$ 897,722	$ 2,370,807

Monticello LCM/EPU Project
Payroll Costs in Common Workorder #10435578 Through August 31, 2013

Sum of Amount			Year							
CodeSour	BU	BUDescription	2007	2008	2009	2010	2011	2012	2013	Grand Total
PAYROLL	257101	HQ Quality Assurance/NOS		$ 30,813	$ 60,825	$ 77,667	$ 24,194	$ 5,796	$ 1,513	$ 200,808
	257105	HQ Project Mgmt Office		$ 111,449	$ 160,268	$ 33,760	$ 478		$ 3,185	$ 309,140
	257107	HQ Licensing		$ 27,698	$ 23,154	$ 27,041	$ 16,398	$ 26,477	$ 35,145	$ 155,914
	257108	HQ Nuclear Anal & Design		$ 6,226	$ 8,844	$ 19,040	$ 33,322	$ 6,234	$ 4,625	$ 78,291
	257110	HQ Engineering Programs		$ 946			$ 497	$ 6,679	$ 862	$ 8,984
	257127	HQ PERFORMANCE IMPROVEMENT							$ 14,285	$ 14,285
	257200	MT Site Management							$ 2,093	$ 2,093
	257202	MT Quality Assurance/NOS				$ 657	$ 8,528			$ 9,184
	257203	MT Quality Control		$ 10,088	$ 45,401	$ 48,679	$ 50,167	$ 576	$ 63	$ 154,973
	257206	MT Chemistry					$ 31,721			$ 31,721
	257211	MT Maint - Electrical						$ 516		$ 516
	257212	MT Maint - I&C		$ 6,973			$ 1,972			$ 8,944
	257213	MT Maint - Support							$ 381	$ 381
	257214	MT Maint-Craft Aug		$ 252,321	$ 529,716	$ 441,947	$ 1,994,404	$ 301,496	$ 3,539,052	$ 7,058,936
	257215	MT Maint - Facilities						$ 4,273		$ 4,273
	257217	MT Rad Protection			$ 82,844	$ 37,789	$ 113,364			$ 233,998
	257222	MT Shift Operations					$ 35,374	$ 39,453	$ 16,958	$ 91,785
	257224	MT Work Control Center			$ 29,879	$ 104,681				$ 134,560
	257227	MT Outage				$ 14,077	$ 2,723	$ 21,982	$ 7,424	$ 46,206
	257228	MT Scheduling				$ 283				$ 283
	257230	MT Project Management		$ 1,285,039	$ 1,021,168	$ 891,572	$ 654,487	$ 329,591	$ 346,469	$ 4,528,325
	257232	MT Training - Operations				$ 2,412	$ 6,022	$ 3,618		$ 12,053
	257234	MT Training - Maint		$ 30,984						$ 30,984
	257235	MT Training - Simulator					$ 1,616	$ 25,936	$ 16,612	$ 44,165
	257237	MT Licensing			$ 2,836					$ 2,836
	257244	MT EngSys-NSSS / REACTOR		$ 1,125					$ 3,361	$ 4,486
	257245	MT Eng Systems - Elec/I&C		$ 10,780	$ 1,943	$ 906				$ 13,629
	257247	MT Eng Systems - Plant		$ 1,387						$ 1,387
	257250	MT Eng Prog-LT Term Prog		$ 31,361	$ 11,768	$ 33,698	$ 9,424			$ 86,251
	257251	MT Eng Prog - Equip Rel P		$ 4,290	$ 2,714	$ 7,669	$ 962	$ 2,889	$ 3,202	$ 21,726
	257253	MT Engineering Design		$ 46,193	$ 8,705	$ 63,802	$ 79,755	$ 66,922	$ 124,469	$ 389,846
	257254	MT Eng Design-Mechanical		$ 544	$ 4,509		$ 9,067			$ 14,120
	257255	MT Eng Design-Electrical		$ 3,733	$ 2,264					$ 5,996
	257257	MT Eng Design - Support		$ 181,882	$ 329,742	$ 42,899	$ 13,711			$ 568,234
	257258	MT Records Mgmt/Doc Control						$ 3,019	$ 3,207	$ 6,226
	257259	MT Procedures Mgmt		$ 30,083	$ 38,258					$ 68,340
	257260	MT Information Technology			$ 4,979					$ 4,979
	257261	MT Administration Svcs		$ 30		$ 532	$ 1,737	$ 876	$ 37,504	$ 40,678
	257262	MT Business Planning					$ 14,640			$ 14,640
	257403	PI Quality Control			$ 13,902					$ 13,902
	257430	PI Project Management				$ 4,284	$ 6,575		$ 207	$ 11,066
	265607	ES Maintenance Resources Mgr		$ 6,749	$ 13,989	$ 353	$ 369			$ 21,459
	265905	ES MN Craft Workers O&M				$ 415			$ 90,584	$ 90,999
	270015	ES Monticello #1 Capital	$ 12,079		$ 3,374					$ 15,454
	556726	BS NUC Process Controls Monti					$ 41,621	$ 382	$ 54,754	$ 96,757
	620100	GC Legal Services			$ 2,575			$ 16,728	$ 1,123	$ 20,426
	625400	RR-Regulatory Admin North		$ 25,661	$ 799	$ 284				$ 26,744
	625450	RR-Regulatory Policy - North		$ 10,633						$ 10,633
PAYROLL Total			$ 12,079	$ 2,116,988	$ 2,404,454	$ 1,854,446	$ 3,153,128	$ 863,443	$ 4,307,077	$ 14,711,614

BU	SUMMARY BY MAJOR CATEGORY								
	Maintenance & Operations	Project Mgmt	Engineering	Quality Assur / Contrl	Process / Procedures / Controls	Chemistry & Rad Protection	Licensing & Training	Other	Description of Other
257101				$ 200,808					
257105		$ 309,140							
257107							$ 155,914		
257108								$ 78,291	HQ Nuclear Anal & Design
257110			$ 8,984						
257127								$ 14,285	HQ PERFORMANCE IMPROVEMENT
257200								$ 2,093	MT Site Management
257202				$ 9,184					
257203				$ 154,973					
257206						$ 31,721			
257211	$ 516								
257212	$ 8,944								
257213	$ 381								
257214	$ 7,058,936								
257215	$ 4,273								
257217						$ 233,998			
257222	$ 91,785								
257224					$ 134,560				
257227								$ 46,206	MT Outage
257228								$ 283	MT Scheduling
257230		$ 4,528,325							
257232							$ 12,053		
257234							$ 30,984		
257235							$ 44,165		
257237							$ 2,836		
257244			$ 4,486						
257245			$ 13,629						
257247			$ 1,387						
257250			$ 86,251						
257251			$ 21,726						
257253			$ 389,846						
257254			$ 14,120						
257255			$ 5,996						
257257			$ 568,234						
257258					$ 6,226				
257259					$ 68,340				
257260								$ 4,979	MT Information Technology
257261								$ 40,678	MT Administration Svcs
257262								$ 14,640	MT Business Planning
257403				$ 13,902					
257430		$ 11,066							
265607	$ 21,459								
265905	$ 90,999								
270015								$ 15,454	ES Monticello #1 Capital
556726					$ 96,757				
620100								$ 20,426	GC Legal Services
625400								$ 26,744	RR-Regulatory Admin North
625450								$ 10,633	RR-Regulatory Policy - North
PAYROLL Total	$ 7,277,293	$ 4,848,531	$ 1,114,659	$ 378,868	$ 305,883	$ 265,719	$ 245,951	$ 274,712	

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PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED

Monticello LCM/EPU Project
Overhead Costs in Common Workorder #10435578 by Source and Year
(2013 Costs Through August 31)

Sum of Amount		Year										
CodeSource	CodeDesc	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Grand Total
OVERHEAD	E&S					$ 213,463	$ (847,100)	$ 612,232	$ 1,694,506	$ (6,657)	$ 5,045	$ 1,671,489
	PwrPlant	$ 1,268	$ 0	$ 2,081	$ 12,324	$ 65,098	$ (211,658)	$ 742,091	$ (390,004)	$ 61,567	$ 112,180	$ 394,947
OVERHEAD Total		$ 1,268	$ 0	$ 2,081	$ 12,324	$ 278,561	$ (1,058,758)	$ 1,354,323	$ 1,304,502	$ 54,910	$ 117,225	$ 2,066,436

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED

Monticello LCM/EPU Project
Employee Expenses in Common Workorder Costs #10435578 Through August 31, 2013
Expenses Charged Through Expense Report System

Sum of Amount				Year						
CodeSource	CodeDesc	GL	GLDesc	2008	2009	2010	2011	2012	2013	Grand Total
EXPENSES	Expense Reports	731800	CWIP Materials		$ 100					$ 100
		731850	CWIP Material-Sm Cap Purchases	$ 20,483	$ 30,736	$ 35,862	$ 61,828	$ 2,145	$ 14,027	$ 165,082
		732350	CWIP Personal Comm Devices		$ 100	$ 550				$ 650
		732400	CWIP Employee Expenses*	$ 104,254	$ 23,844					$ 128,098
		732405	CWIP EE Exp Airfare		$ 12,222	$ 16,100	$ 3,735	$ 4,373	$ 2,752	$ 39,182
		732410	CWIP EE Exp Car Rental		$ 885	$ 2,877	$ 706	$ 11		$ 4,478
		732415	CWIP EE Exp Taxi/Bus		$ 134	$ 102	$ 9	$ 32	$ 97	$ 374
		732420	CWIP EE Exp Milage		$ 1,383	$ 2,897	$ 2,292	$ 2,522	$ 2,107	$ 11,200
		732430	CWIP EE Exp Hotel		$ 3,614	$ 9,881	$ 2,534	$ 917	$ 1,419	$ 18,365
		732435	CWIP EE Exp Meals-EE's		$ 1,368	$ 1,545	$ 536	$ 184	$ 252	$ 3,885
		732445	CWIP EE Exp Parking		$ 693	$ 1,079	$ 345	$ 290	$ 243	$ 2,650
		732455	CWIP EE Exp Safety Equip			$ 100				$ 100
		732460	CWIP EE Exp Other		$ 142	$ 2,970	$ 554			$ 3,666
		732800	CWIP License Fees & Permit	$ 374		$ 67				$ 440
		733000	CWIP Rents Equipment				$ 556			$ 556
		733300	CWIP Other	$ 175	$ 26					$ 201
EMPLOYEE EXPENSES Total				$ 125,286	$ 75,246	$ 74,031	$ 73,094	$ 10,475	$ 20,897	$ 379,028

*Note: More Detailed Expense Accounts Were Created in 2009

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	042
Requestor:	Nancy Campbell, Chris Shaw & Steve Rakow		
Date Received:	December 10, 2013		

Question:

Reference: Page 93 Table 14 and page 97 Table 15 of Direct Testimony of O'Connor

Why did the Company wait until 2011 to review and assign "Common Costs" related to 2009 in-service projects such as Turbine Replacement, Power Range Neutron Monitor System, Main Transformers, and Feedwater Heaters?

Response:

For construction projects that have multiple subprojects coordinated under a single overall project, it has been the Company's common practice to direct assign costs to individual subprojects whenever possible and to accumulate and assign indirect costs common to all subprojects using an allocation process.

This cost allocation process typically occurs by assigning, on a pro rata basis, the common costs to the direct costs charged to subprojects. That process is fairly simple for a shorter term project when common costs and total project costs are readily determinable.

However, in applying this approach to the Monticello LCM/EPU Project, estimates of common costs and total project costs – the numerator and denominator in the cost allocation process, respectively – we knew there were already many changes occurring as we began to expand project work orders. Specifically, in 2009 we still had some significant costs that we knew could be directly assigned to subproject child work orders, such as licensing, that were included in vendor invoices initially recorded with the common costs. While we were able to direct assign these amounts from information obtained by vendors, that process was manual and would take time. In consultation with Capital Asset Accounting, we decided that, rather than making preliminary estimates at that time of directly assignable costs and the remaining common costs to be allocated, we would wait until we completed the direct assignment process to make the allocations. Allocating costs early in the implementation phase using preliminary cost estimates that were likely to change would make the early allocations outdated over time and not as accurate as when we were further into the project. .

The result was a delay in the initial allocation of common costs, until after the more significant additions occurred in the 2011 outage. Once completed, those common cost allocations did move costs to all subprojects completed as of that date including work in-serviced in 2009.

We believe the result of this cost allocation process, although not deployed immediately when the Project's first equipment was placed in-service in 2009, resulted in a proper allocation of common costs to all subproject child work orders over the entire project duration.

Preparer:	Scott L. Weatherby / Lisa H. Perkett
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Department:	Nuclear Finance & Planning / Capital Asset Accounting
Telephone:	612-330-7643 / 612-330-6950
Date:	December 24, 2013

State of Minnesota
Department of Commerce
Division of Energy Resources

Utility Information Request Response

Docket Number: E002/CI-13-754 (Commission Investigation into the Monticello LCM/EPU Project)

Date Request Received: July 24, 2014

Date of Response: August 5, 2014

Person Requesting Information: Timothy J. O'Connor

Response submitted by: Mark W. Crisp

Request No.	
6	Re: Direct Testimony and Attachments of Mark W. Crisp Reference Crisp p. 5, lines 20-22. You state: "Xcel and GE, now GE Hitachi, would have produced an 'as-built' summary of the design modifications in the first uprate in order to meet NRC requirements and to receive NRC approval." Please identify the specific NRC requirement(s) you are referring to in that sentence. **DOC Response:** NRC QA Program Procedure 35742B Issue Date 7/1/1980 NRC Inspection Procedure 37051 "Verification of As-Builts" Issue Date 12/4/1987 10 CFR 50 and Appendices 10 CFR 52 and Appendix ANSI N45.2 ASME NQA 1 Monticello Quality Assurance Program required by the NRC Original Monticello Plant Safety Analysis Report ("SAR"), and subsequent revisions to same.

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002/CI-13-754
Response To: Department of Commerce Information Request No. 027
Requestor: Nancy Campbell, Chris Shaw & Steve Rakow
Date Received: December 10, 2013

Question:

Reference: Testimony and Schedules of J.A. Stall page 62, lines 10 to 14 stated: "With a 40-year-old plant it is unsurprising that the as-built drawings did not completely match the actual as-found conditions.
In my interviews with Xcel Energy personnel, I understood that they encountered many instances where field design changes were required as a result of drawing discrepancies." Please explain why drawing discrepancies are expected or "unsurprising"?

Response:

Drawing discrepancies are not surprising because the over 40-year old facility has never been through an "as-built" reconstitution of its drawings. During the timeframe that first generation nuclear plants were constructed, it was not unusual that the "as built" configuration of non-safety related secondary plant systems were not fully documented on plant drawings, as many of the mechanical systems were "field run" (skilled craft labor determine the installation routing) to facilitate ease of installation. This was in keeping with methodologies used in fossil plants of that era. As a result, it is not uncommon to find legacy issues with the plant design drawings, particularly with, the electrical drawings but also piping as well. Thus, there will be discrepancies between the actual location of facilities and the drawings. At the time the plant was built in the 1960's there was little thought given to the fact that major upgrades would be needed for extending the life of the plant, and it was assumed that the original equipment would last the original 40 years. This issue is not unique to Monticello.

In Mr. O' Connor's experience working at other plants, major projects often were impacted by differences in the "as built" and filed conditions. In Mr. Stall's experience with the upgrades at the Florida Power & Light plants, he also encountered many situations where as built drawings did not match field conditions, for the same reason stated above.

We note that in 1987, the Company made a formal commitment [NRC Commitment M87005A] to the NRC that required electrical prints to be as-built verified for each project that modifies the plant. This is the way of mitigating the risk incurred by working with drawings that do not reflect the as-built configuration of the plant. Design Engineering revised the corporate modification process to comply with the NRC commitment. The commitment is part of fleet procedure FP-E-MOD-09, Installation and Testing Instructions. The volume of modification work associated the LCM/EPU project affected a significant number of systems that had not previously been updated.

In addition, while we were under no commitment to update the drawings for other non-safety systems, our procedure is that the plant revises drawings when discrepancies are found, which is a way to manage on-going nuclear operations costs. But like many other aspects of the facility many of these had not been mapped to as built drawings over time. This was particularly true of piping installations. As described in our response to DOC IR 28, piping interferences resulted in a significant number of field changes to address identified discrepancies.

Preparer:	Timothy J. O'Connor/Mark Schimmel/ J. Arthur Stall
Title:	Chief Nuclear Officer/Vice President, Nuclear/ President
Department:	Nuclear Operations/ JAS Consulting
Telephone:	612-215-4613/ 772-221-0575
Date:	December 24, 2013

NRC COMMUNICATIONS LOG
JUNE 2007 TO JUNE 2014

Date	Discussion topic(s)	Type of Communications
06-05-2007	Pre-application Meeting for Monticello Extended Power Uprate ("EPU")	Verbal
02-13-2008	Original Steam Dryer Results for EPU analysis	Verbal
05-12-2008	Monticello EPU acceptance review - Mechanical Branch	Verbal
05-14-2008	Public meeting - Monticello EPU License Amendment Request ("LAR")	Verbal
05-16-2008	Monticello EPU acceptance review - Reactor System Branch	Verbal
11-05-2008	NSPM letter to NRC- EPU LAR	Written
11-19-2008	Public meeting – Monticello EPU LAR	Verbal
12-03-2008	NRC to NSPM telephone discussion of Probabilistic Risk Assessment issues in EPU LAR	Verbal
12-05-2008	NRC email to NSPM, regarding Probabilistic Risk Assessment Branch Request for Additional Information ("RAI") for EPU LAR	Written
12-09-2008	NRC and NSPM teleconference regarding revised RAI questions on containment analysis	Verbal
12-11-2008	NSPM letter to NRC acceptance review supplement – regarding steam dryer outer hood submodel analysis	Written
12-16-2008	NRC email to NSPM, draft RAI questions on environmental issues of EPU application and conference call set-up	Written
12-18-2008	NRC letter to NSPM finding EPU LAR acceptable for review	Written
12-18-2008	NRC email to NSPM regarding revised RAI on containment analysis	Written
12-18-2008	Conference call on RAI questions for proposed EPU amendment, environmental issues	Verbal
12-18-2008	NRC email to NSPM regarding additional RAI question for proposed EPU amendment, environmental issues	Written
01-14-2009	NRC letter to NSPM granting request for withholding of proprietary information found in enclosure 5 of the EDU LAR from public disclosure as requested in NSPM's 11/5/2008 letter	Written
01-16-2009	NRC email to NSPM regarding draft RAIs from Nuclear Performance & Code Review Branch	Written
01-26-2009	NRC letter to NSPM granting request for withholding of proprietary information found in enclosure 11 of the EDU LAR from public disclosure as requested in NSPM's 11/5/2008 letter	Written
01-29-2009	NSPM letter to NRC with responses to NRC's RAIs on environmental issues	Written
01-30-2009	NRC letter to NSPM issuing amendment authorizing installation and use of power range neutron monitoring system	Written
02-04-2009	NSPM letter to NRC regarding revision to attachment 1 of enclosure 17 of November 5, 2008 EPU LAR	Written

Date	Discussion topic(s)	Type of Communications
02-04-2009	NSPM letter to NRC with responses to NCR's RAIs from Probabilistic Risk Assessment Branch	Written
02-11-2009	NRC email to NSPM regarding draft RAI from Materials Engineer regarding the proposed EPU amendment	Written
02-17-2009	NSPM letter to NRC with responses to NRC's RAIs on containment analysis	Written
02-23-2009	NRC email to NSPM regarding draft RAIs from Nuclear Performance & Code Review Branch	Written
02-24-2009	NSPM letter to NRC with responses to NRC's RAIs from Steam Generator Tube Integrity & Chemical Engineering Branch	Written
03-11-2009	NRC email to NSPM with draft RAIs from Instrument and Controls Branch regarding EPU LAR and conference call set-up	Written
03-11-2009	Conference call on draft RAIs from Nuclear Performance & Code Review Branch	Verbal
03-12-2009	NRC email to NSPM with draft RAIs from Fire Protection Branch and conference call set-up	Written
03-18-2009	NRC email to NSPM regarding 2/4/09 supplement on Probabilistic Risk Assessment issues with additional RAIs and conference call set-up	Written
03-19-2009	NRC email to NSPM regarding draft RAIs from Containment and Ventilation Branch and conference call set-up	Written
03-19-2009	NSPM letter to NRC with responses to NRC's RAIs from Nuclear Performance & Code Review Branch dated 01/16/2009	Written
03-20-2009	NRC email to NSPM regarding draft RAIs from Reactor Inspection Branch related to health physics area	Written
03-23-2009	NRC email to NSPM regarding draft RAIs from Balance of Plant Branch and conference call set-up	Written
03-28-2009	NRC email to NSPM regarding draft RAIs from Electric Engineering Branch and conference call set-up	Written
03-28-2009	NRC email to NSPM regarding additions to 3/20/2009 draft RAIs from Mechanical & Civil Engineering Branch on steam dryer	Written
03-29-2009	NRC email to NSPM regarding additional draft RAIs from Containment and Ventilation Branch	Written
04-02-2009	Conference call on additional RAIs from Instrumentation and Controls Branch	Verbal
04-06-2009	NRC email to NSPM regarding additional RAI from Instrumentation and Controls Branch	Written
04-17-2009	Conference call on revisions to draft RAIs dated 3/18/2009 from Probabilistic Risk Assessment Branch	Verbal
04-22-2009	NRC email to NSPM requesting audit of long-term stability solution for the EPU amendment	Written
04-22-2009	NSPM letter to NRC with responses to NRC's RAIs from Nuclear Performance & Code Review Branch dated 2/23/2009	Written

Date	Discussion topic(s)	Type of Communications
04-29-2009	NRC email to NSPM regarding revisions to 3/18/2009 draft RAIs from Probabilistic Risk Assessment Branch	Written
05-07-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 4/22/2009 letter	Written
05-13-2009	NSPM letter to NRC with responses to NRC's RAIs from Instrumentation & Controls Branch dated 3/12/2009	Written
05-26-2009	NSPM letter to NRC with responses to NRC's RAIs from Electrical Engineering Review Branch dated 3/28/2009	Written
05-29-2009	NSPM letter to NRC with responses to NRC's RAIs from Probabilistic Risk Assessment Branch dated 4/29/2009	Written
06-08-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 5/13/2009 letter	Written
06-12-2009	NSPM letter to NRC with responses to NRC's RAIs from Balance of Plant Review Branch dated 3/23/2009	Written
06-16-2009	NSPM letter to NRC with responses to NRC's RAIs from Reactor Inspection Branch dated 3/20/2009	Written
06-26-2009	NRC email to NSPM regarding additional RAI on steam dryer	Written
07-02-2009	NRC email to NSPM regarding open issues in 5/13/2009 RAI response and to set-up conference call	Written
07-02-2009	NRC email to NSPM regarding draft RAIs related to containment overpressure and request to set-up conference call	Written
07-06-2009	Teleconference regarding open issue from Fire Protection Board RAI dated 3/20/2009	Verbal
07-13-2009	NSPM letter to NRC with responses to NRC's Containment and Ventilation Review Branch RAIs dated 3/19/2009	Written
07-16-2009	NRC letter to NSPM regulatory audit summary regarding EPU and long-term stability solution	Written
07-23-2009	NSPM letter to NRC with responses to NRC's Reactor Systems Review Branch RAIs dated 3/23/2009 and Nuclear Code & Performance Review Branch RAIs dated 4/27/2009	Written
08-12-2009	NSPM letter to NRC with responses to NRC's Fire Protection Branch RAI dated 7/2/2009	Written
08-12-2009	NSPM letter to NRC with responses to NRC's Mechanical and Civil Engineering Review Branch RAIs dated 3/20/2009	Written
08-14-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 3/19/2009 letter	Written
08-14-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 7/23/2009 letter	Written
08-19-2009	NSPM letter to NRC with response to RAI No. 3 dated 4/6/2009 from NRC's Instrumentation and Controls Branch	Written

Date	Discussion topic(s)	Type of Communications
08-21-2009	NSPM letter to NRC with responses to NRC's Mechanical and Civil Engineering Review Branch RAIs dated 3/28/2009	Written
08-21-2009	NSPM letter to NRC with responses to NRC's Containment and Ventilation Review Branch RAIs dated 7/2/2009	Written
08-26-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 8/12/2009 letter	Written
08-26-2009	NSPM letter to NRC with responses to NRC's Mechanical and Civil Review Branch RAIs dated 3/20/2009	Written
08-28-2009	NRC letter to NSPM with draft Environmental Assessment for the proposed EPU amendment	Written
08-31-2009	NSPM letter to NRC with supplement to EPU LAR containing revisions to proposed technical specification changes	Written
09-09-2009	Executive drop-in regarding major capital projects organization and submittals	Verbal
09-15-2009	The NRC's plan of action regarding Containment Accident Pressure and its impact on the Monticello EPU LAR	Verbal
09-16-2009	A Follow up to September 15, 2009 conference call with NRC to discuss plan of action regarding Containment Accident Pressure and its impact on the Monticello EPU LAR	Verbal
09-28-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 8/21/2009 letter responding to RAIs from Containment and Ventilation Branch	Written
09-28-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 8/26/2009 letter	Written
09-28-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 8/21/2009 letter responding to RAIs from Mechanical and Civil Engineering Branch	Written
09-28-2009	Drop in meeting regarding perspectives on path to resolution for Containment Accident Pressure issue with NRC and ACRS	Verbal
10-01-2009	NRC letter to NSPM regarding revised schedule for EPU amendment application review	Written
10-01-2009	NSPM letter to NRC revising enclosures 5 and 7 of EPU LAR dated 11/5/2008	Written
10-01-2009	Follow up to September 15 and 16 conference calls with NRC to siscuss plan of action regarding Containment Accident Pressure and its impact on the Monticello EPU LAR	Verbal
10-13-2009	NSPM letter to NRC acknowledging receipt of revised review schedule for EPU amendment application	Written

Date	Discussion topic(s)	Type of Communications
10-20-2009	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 10/1/2009 letter	Written
10-23-2009	Executive Drop-in – Monticello EPU delay and concurrent review of Maximum Extended Load Line Limit Analysis Plus ("MELLLA+")	Verbal
10-25-2009	NRC email to NSPM regarding draft technical position on NSPM's 7/13/2009 response to Containment System RAIs	Written
10-28-2009	NSPM letter to NRC request for NRC concurrent review of MELLLA+ LAR with EPU LAR review delay	Written
11-05-2009	NRC email to NSPM regarding draft RAI related to NSPM response dated 8/21/2009 and request to set up conference call	Written
11-13-2009	Teleconference regarding review of MELLLA+ concurrent with EPU	Verbal
11-23-2009	NRC letter to NSPM granting request to have concurrent MELLLA+ LAR review and EPU LAR review	Written
11-24-2009	1. Monticello HELB Applicability Criteria 2. Monticello Piping Design Analysis Regulatory Review and Status	Verbal
12-15-2009	MELLLA + pre-application meeting	Verbal
01-08-2010	NRC and NSPM conference call on RAI steam dryer EPU issues	Verbal
01-11-2010	Final version summary of conference call attendees	Written
01-11-2010	NRC letter to NSPM with final Environmental Assessment and finding of no significant impact	Written
01-14-2010	Review of HELB selection criteria licensing basis white paper	Verbal
01-21-2010	NSPM letter to NRC regarding MELLLA+ LAR	Written
01-25-2010	NSPM letter to NRC updates to enclosures contained in 11/5/2008 EPU LAR, subsequent technical specifications from 8/31/2009 and RAI response to Mechanical and Civil engineering review branch dated 8/21/2009	Written
02-19-2010	Monticello MELLLA+ regarding supplemental information needed to complete acceptance review	Verbal
02-25-2010	More on status of EMCB non-steam dryer portion of the Monticello EPU	Verbal
02-26-2010	NRC email to NSPM regarding conference call on 2/25/2010 affirming withdrawal of NRC RAI regarding high energy line breaks	Written
03-04-2010	NSPM letter to NRC with supplemental information for MELLLA+ acceptance review	Written
03-12-2010	NSPM letter to NRC requesting extension of permanent relief from volumetric examination of reactor pressure vessel circumferential shell welds for the renewed operating license term	Written
04-06-2010	NSPM letter to NRC with responses to 2/25/2010 conference call	Written

Date	Discussion topic(s)	Type of Communications
04-06-2010	NRC email to NSPM regarding additional draft RAI's from Containment and Ventilation Branch	Written
04-08-2010	April 2010 Containment and Ventilation Branch Draft RAIs	Verbal
04-15-2010	Management drop-in meeting regarding the change in strategy to use the Nordic steam dryer in the EPU LAR	Verbal
04-23-2010	NSPM presented an overview of the dryer design, a summary of the Nordic steam dryers' opera ting experience, technical highlights of the design, testing and its compliance with Reg. Guide 1.20, and the final dryer's compliance to its acceptance criteria.	Verbal
06-10-2010	NSPM shipment to NRC with revisions to Inservice Inspection Examination plan	Written
06-30-2010	NSPM letter to NRC regarding replacement steam dryer supplement	Written
07-09-2010	Potential to restart of Monticello EPU LAR review	Verbal
07-15-2010	BWROG meeting with NRC regarding proposed items for NRC Staff/BWROG discussion of use of Containment Accident Pressure for NPSH margin determination	Verbal
07-19-2010	MELLLA+ draft RAIs from submittal L-MT-10-003	Verbal
07-29-2010	Restarting the NRC Review of the Monticello EPU application and analyses required	Verbal
07-30-2010	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 6/30/2010 letter related to enclosures in the replacement steam dryer supplement	Written
07-30-2010	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 6/30/2010 letter related to an appendix in the replacement steam dryer supplement	Written
08-02-2010	MELLLA+ draft RAIs from submittal L-MT-10-003	Verbal
09-17-2010	NSPM letter to NRC regarding revisions to the Minimum Critical Power Safety Limit in Reactor Core Safety Limit 2.1.1.2	Written
09-28-2010	NSPM letter to NRC with response to MELLLA+ RAIs dated 07/31/2010 and 08/13/2010	Written
11-11-2010	Conference call on replacement steam dryer draft RAIs	Verbal
12-10-2010	NRC inspection activities associated with EPU	Verbal
12-21-2010	NSPM letter to NRC regarding updates to docket information provided in EPU application	Written
01-17-2011	Clarification of MELLLA+ RAIs 22 - 24 from submittal L-MT-10-049	Verbal
02-11-2011	NRC staff and ACRS discussion of Staff SECY letter 11-0014 on use of Containment Accident Pressure	Verbal
02-14-2011	Containment Accident Pressure options described in SECY letter	Verbal

Date	Discussion topic(s)	Type of Communications
02-22-2011	BWROG discussion with NRC on use of computational fluid dynamics to address NPSH concerns for Containment Accident Pressure	Verbal
02-22-2011	Exelon discussion with NRC on strategies for Containment Accident Pressure elimination	Verbal
03-04-2011	conference call regarding replacement steam dryer design and qualification	Verbal
03-05-2011	Replacement steam dryer RAI on direct versus indirect measurement for qualification of the replacement steam dryer at EPU Power Levels	Verbal
03-16-2011	NRC email to NSPM regarding additional draft RAIs for EPU replacement Steam Dryer	Written
03-17-2011	Replacement Steam Dryer discussion regarding licensing approach and request for audit of WEC documentation for steam dryer	Verbal
04-04-2011	Containment Accident Pressure questions in relation to SECY 11-0014	Verbal
04-05-2011	NRC letter to NSPM notifying of reactivation of review of the proposed EPU amendment	Written
04-07-2011 – 04-08-2011	Licensing path and technical discussions for Monticello replacement steam dryer	Verbal
04-11-2011	Interface between EPU and PTLR amendment	Verbal
05-12-2011	MELLLA + RAI responses	Verbal
07-08-2011	NRC letter to NSPM related to results of audit report of use of Nordic steam dryer for EPU	Written
07-18-2011	Containment Accident Pressure update - NRC technical discussion on technical positions related to Containment Accident Pressure	Verbal
08-15-2011	Containment Accident Pressure calculations methods and approaches	Verbal
08-23-2011	MELLLA + simulator audit – preparations	Verbal
08-25-2011	Containment Accident Pressure calculations methods and approaches	Verbal
08-30-2011	NSPM letter to NRC regarding updates on EPU commitments	Written
09-12-2011	NRC email to NSPM regarding draft RAIs of ECCS analysis for EPU application	Written
11-11-2011	NSPM letter to NRC correcting analysis error in EPU and MELLLA+ LARs	Written
11-30-2011	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 11/11/2011 letter	Written
12-15-2011	BWROG Containment Accident Pressure activity update	Verbal
01-13-2012	NSPM letter to NRC with initial response to RAIs related to EPU replacement steam dryer	Written

Date	Discussion topic(s)	Type of Communications
01-20-2012	NSPM letter to NRC LAR to revise and relocate Pressure Temperature Curves to a Pressure Temperature Limits Report	Written
03-19-2012	Update on status of Containment Accident Pressure and discussion of path forward	Verbal
04-03-2012	NRC meeting: alternative regulatory path for Containment Accident Pressure	Verbal
06-27-2012	NSPM letter to NRC supplement to MELLLA+ LAR	Written
07-19-2012	NSPM letter to NRC responses to RAIs related to replacement steam dryer	Written
08-07-2012	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 7/9/2012 letter	Written
08-23-2012	NRC audit of simulator for MELLLA+	Verbal
10-16-2012	MELLLA + draft RAIs dated 10-4-2012	Verbal
10-22-2012	NSPM letter to NRC regarding Inspection Criteria and Plan for EPU replacement steam dryer	Written
10-30-2012	NSPM letter to NRC requesting revisions to the Technical Specification Setpoint for the automatic depressurization system bypass timer changes proposed under the EPU amendment	Written
11-20-2012	Discussion of gap analysis regarding items needed to complete licensing of EPU LAR	Verbal
11-30-2012	NSPM letter to NRC regarding supplements to address SECY 11-0014 use of Containment Accident Pressure	Written
12-04-2012	NRC steam dryer RAIs dated 11/8/2012	Verbal
12-13-2012	NRC summary of public meeting with NSPM regarding EPU analysis	Written
01-18-2013	Discuss NRC draft steam dryer RAIs and NSPM draft RAI responses	Verbal
01-21-2013	NSPM letter to NRC regarding supplement for gap analysis update	Written
01-31-2013	NSPM letter to NRC responding to RAIS related to Automatic Depressurization System Bypass Timer Setting	Written
02-15-2013	NRC email to NSPM regarding draft RAIs from Containment and Ventilation Branch	Written
02-19-2013	Discuss NRC draft Steam Dryer RAIs and NSPM draft RAI responses	Verbal
02-26-2013	Discuss NRC draft CAP related RAIs and NSPM draft RAI responses	Verbal
02-27-2013	NSPM letter to NRC regarding second supplement for gap analysis updates	Written
03-07-2013	NSPM letter to NRC responding to RAIs related to replacement steam dryer	Written
03-12-2013	NRC email to NSPM regarding draft requests for additional RAIs from Electric Engineering Branch	Written
03-13-2013	Discuss Electrical Branch RAIs dated 3/12/2013	Verbal

Date	Discussion topic(s)	Type of Communications
03-18-2013	NSPM letter to NRC responding to additional RAIs related to the replacement steam dryer	Written
03-21-2013	NSPM letter to NRC responding to RAIs related to SECY 11-0014 use of Containment Accident Pressure	Written
03-21-2013	NRC Meeting regarding MNGP MELLLA + LAR - Quench model error	Verbal
03-27-2013	NRC Meeting regarding MNGP MELLLA + LAR - Quench model error	Verbal
03-28-2013	NRC email to NSPM regarding additional RAIs from Reactor Systems Branch	Written
03-29-2013	NSPM letter to NRC responding to additional RAIs related to the replacement steam dryer	Written
04-10-2013	NSPM letter to NRC responding to RAIs from the Electrical Engineering Branch	Written
04-15-2013	NRC Meeting regarding MNGP MELLLA + LAR - Quench model error	Verbal
04-24-2013	NRC email to NSPM regarding additional RAIs from the Containment and Ventilation Branch	Written
04-26-2013	NRC Meeting regarding Thermal Conductivity Degradation incorporation into EPU and MELLLA + LARs	Verbal
05-08-2013	NRC Meeting regarding Thermal Conductivity Degradation incorporation into EPU and MELLLA + LARs	Verbal
05-08-2013	Drop-in meeting with NRC EPU /MELLLA +	Verbal
05-10-2013	NRC email to NSPM regarding RAIs from Mechanical and Civil Engineering Branch	Written
05-13-2013	NSPM letter to NRC providing basis for concluding that the analyses and conditions evaluated in license amendment 172 satisfy the P-T limits applicable under both EPU and MELLLA+ conditions.	Written
05-17-2013	NRC email to NSPM regarding draft RAIS from the Reactor Systems Branch and Vessel & Internals Integrity Branch	Written
05-22-2013	Discuss NRC draft steam dryer RAIs and NSPM draft RAI responses	Verbal
05-22-2013	Discuss NRC draft RAIs on Fluence and Upper Shelf Energy	Verbal
05-25-2013	Transmit comment list for EPU SE	Verbal
05-30-2013	NSPM letter to NRC responding to RAIs from Reactor Systems Branch and Containment and Ventilation Branch	Written
06-04-2013	Discuss NRC draft steam dryer RAIs and NSPM draft RAI responses	Verbal
06-20-2013	Discuss NRC draft steam dryer RAIs and NSPM draft RAI responses	Verbal
06-21-2013	GEH webcast discussion of TRACG error with NRC - MELLLA+ LAR	Verbal

Date	Discussion topic(s)	Type of Communications
06-26-2013	NSPM letter to NRC responding to RAIs from Reactor Systems Branch and Vessel & Internals Integrity Branch	Written
06-28-2013	NRC Meeting regarding TCD incorporation into EPU and MELLLA + LARs and supplemental information related to IMLTR limitation for EPU	Verbal
07-08-2013	NSPM letter to NRC regarding supplement for analytical methods used to address Thermal Conductivity Degradation and analytical methods limitations	Written
07-09-2013	NRC email to NSPM regarding RAIs from Vessel & Internals Integrity Branch	Written
07-10-2013	Discuss NRC preparations for ACRS meeting relative to steam dryer review and NRC clarifications	Verbal
07-15-2013	NSPM letter to NRC regarding LAR for transition to AREVA ATRIUM 10XM fuel and AREVA safety analysis methodology	Written
07-18-2013	NSPM letter to NRC responding to RAIs related to status of Safety Communications Review	Written
07-18-2013	NSPM letter to NRC responding to RAIS related to replacement steam dryer	Written
07-19-2013	Discuss NRC preparations for ACRS meeting relative to steam dryer review and NRC clarifications	Verbal
07-25-2013 – 07-26-2013	ACRS subcommittee meeting for Monticello EPU application	Verbal
08-02-2013	NSPM letter to NRC responding to RAIs related to replacement steam dryer	Written
08-12-2013	EPU draft Safety Evaluation review meeting	Verbal
08-29-2013	NSPM letter to NRC responding to RAIs related to the replacement steam dryer	Written
09-05-2013	ACRS committee meeting for Monticello EPU application	Verbal
09-25-2013	EPU draft Safety Evaluation review meeting	Verbal
09-30-2013	NSPM letter to NRC to provide closure of completed EPU commitments and revised Power Ascension Test Plan	Written
09-30-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 8/2/2013 letter	Written
09-30-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 7/18/2013 letter	Written
09-30-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 3/29/2013 letter	Written
09-30-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 3/18/2013 letter	Written

Date	Discussion topic(s)	Type of Communications
09-30-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 3/7/2013 letter	Written
09-30-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 2/22/2013 letter	Written
10-08-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 3/21/2013 letter	Written
10-08-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 6/26/2013 letter	Written
10-08-2013	NRC letter to NSPM granting request for withholding of proprietary information from public disclosure as requested in NSPM's 2/27/2013 letter	Written
10-09-2013	EPU draft Safety Evaluation review meeting	Verbal
11-08-2013	NSPM Letter to NRC regarding completion of EPU commitment for piping meeting code requirements	Written
12-03-2013	ACRS subcommittee meeting for MELLLA + License Amendment Request	Verbal
12-09-2013	NRC letter to NSPM issuing Amendment No. 176 to renewed facility operating license regarding EPU	Written
12-18-2013	MELLLA+ - Open items from ACRS subcommittee review held on 12/3/2013	Verbal
12-27-2013	NSPM letter to NRC regarding 2013 annual report of changes and errors in Emergency Core Cooling System evaluations models	Written
01-10-2014	NSPM letter to NRC regarding changes in Emergency Core Cooling System evaluation models	Written
01-15-2014	MELLLA + action items from ACRS subcommittee meeting and ACRS full committee agenda	Verbal
01-23-2014	MELLLA + Action Items from ACRS subcommittee meeting	Verbal
02-05-2014	ACRS committee meeting for Monticello MELLLA + LAR - Review and approval of LAR	Verbal
02-19-2014	MELLLA + license amendment approval - TS clarifications needed	Verbal
03-21-2014	Steam dryer data results package for 1864 MWt discussion	Verbal
03-28-2014	NRC letter to NSPM issuing Amendment No. 180 to renew facility operating license regarding MELLLA+ and redacting the related SE of proprietary information so it can be publically-available	Written
05-30-2014	Steam dryer instrument error description and path forward	Verbal
06-17-2014	NSPM letter to NRC regarding thirty-day report of changes in Emergency Core Cooling Systems evaluation models	Written
06-22-2014	NSPM letter to NRC responding to RAIs related to replacement steam dryer and revised limit curves and supporting information	Written

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	59
Requestor:	Campbell/Shaw	Information Request No.	60
Date Received:	February 28, 2014	Information Request No.	62

Question 59:

Please list any Nuclear Regulatory Commission rule, regulation or interpretation changes that impacted the planned EPU or LCM project budgeted costs or estimates. Include which specific task, activity, work order or subproject was impacted and explain in detail the amount of cost impact. Provide all spreadsheets and other supporting documents. Include and detail the impact of:

a. Evolving NRC standards and requirements due to developments at other plants that have undergone license renewal;

b. Evolving NRC standards and requirements due to developments at other plants that have implemented an EPU;

c. The 2011 events at Fukushima; and

d. Current industry experience and lessons learned.

Question 60:

For each work activity, work order or subproject impacted by changes in NRC rules, regulations or interpretations, please provide a detailed explanation of the actions taken by Xcel to mitigate the cost impact of these changes.

Question 62:

For those NRC related and other factors identified above, please provide the alternatives evaluated for each change including the costs and the reasons for selecting the chosen alternative. Please provide the contemporaneous evaluations and recommendations to management.

Response:[1]

Information Requests DOC-59, 60 and 62 all ask for a discussion of the impact of NRC regulations on the costs incurred for the LCM/EPU Program. This response will provide information relevant to all three of these questions. Documents responsive to this question are provided in response to Information Request DOC-50 and are primarily contained in folders associated with IR DOC-62.

When compared to the initial estimates (see 2007 Nuclear Project Authorization provided in response to IR DOC-50) that the impact of NRC regulations added significant costs to the overall Program implementation.

Cause	Cost
Increase in Licensing Costs	$30+ million (Increase over 2008 estimate)
Additional Calculation Costs	$16+ million
Addition of Steam Dryer	$37+ million (added to scope after 2007 NPA)
Other as described below	Not separately tracked

While we did not separately track costs to specific NRC requirements, we incurred additional design costs necessary to demonstrate Monticello's compliance with all relevant regulatory requirements. Finally, while not tracked in this way, some of the subprojects were necessary to ensure compliance with the NRC's aging management and maintenance rules. Overall we believe that our regulatory compliance was a significant cost driver in the overall costs incurred for the Program.

NRC Regulatory Requirements

Many of the NRC regulatory requirements, such as the license renewal and aging management commitments, prompted decisions to replace or modify certain systems,

[1] Note that all documents referred to in this Response will be produced pursuant to and as part of DOC IR-050, which generally seeks documents responsive to all of DOC IR-048 – 064. The Company notes that a number of the documents provided in response to DOC IR-050 contain confidential employee information, Xcel Energy trade secret information, and third-party trade secret information. Documents produced pursuant to DOC IR-050 will be produced with the appropriate designation as part of our response to that information request. The Company chose this method for producing documents to ensure that the responses to the information requests could be disclosed publicly to the maximum extent possible and to avoid any delay that may occur in preparing voluminous confidential documents for production.

structures and components for the LCM/EPU Program to ensure that the Company could continue to meet NRC requirements and operate safely over the entire license life to 2030.

Licensing Process. Foremost, however, the NRC's licensing process itself required an iterative engineering process to demonstrate Monticello's ability to operate safely at uprate conditions. To obtain the License Amendment Request (LAR) we had to demonstrate that the revised licensing basis of the plant would remain well within Monticello's safety limit and the planned operating limits would remain within the licensing basis for the facility. In some cases the EPU LAR analysis required an analysis of an existing component at an interim power uprate level, and an analysis of a replacement component at the final power uprate level to show that the component would not experience abnormal conditions at either power level. An initial review of each structure, system or component needed to be revised when a connected or supporting system required a change that impacted the original structure or system. Thus, the LAR process itself required a highly iterative engineering process to demonstrate a comprehensive evaluation of the plant.

Importantly, the level of detailed engineering analysis and information sought by the NRC for the EPU LAR increased significantly. During the 2000s, the NRC determined that a higher standard is expected for new EPU LAR submittals as compared to previous EPU LAR submittals. In total we received and responded to more than 460 RAIs pertaining to the EPU and MELLLA+ LARs and despite the NRC's stated 12-month target time to process a LAR, our LAR was pending with the NRC for more than five years. The number of calculations required by the NRC increased dramatically in the time period from the Monticello uprate project in 1998 and resulted in the need for the Company to perform a complete reconstitution of many programs. In addition, substantial changes were required related to instrument setpoint methodology.

The Company did not attempt to track costs associated with the changing regulatory regime that occurred during the period of inception and through construction of the project. Overall, however, our design and engineering costs were approximately $158.8 million, which included both expected design costs and a significant portion attributable to the numerous iterations necessary to demonstrate Monticello's operating ability.

Mitigative Efforts to Streamline the Licensing Process. Throughout the preparation of the LAR we worked with GE and Westinghouse to identify the licensing issues that needed to be addressed. Those issues were identified based on a review of all Monticello specific design and licensing basis requirements, permits, available EPU operating experience, regulatory issues as found in ACRS transcripts and NRC notices, and areas of review contained in NRC Review Standards RS-001.

Xcel Energy's project team also reviewed NRC Requests for Additional Information (RAI) and responses for previous licensees to identify the industry issues that concerned the NRC Staff. We then considered which of those issues should be incorporated into our LAR. Though we anticipated that adherence to RS-001 would reduce the number of RAIs issued, we reviewed other RAIs and responses from other recent EPU applications to anticipate and thus avoid certain inquiries that could have been even taken longer and required additional internal resources to process.

The Monticello team did significant due diligence and background work to understand the regulatory requirements of a nuclear uprate. We met with the NRC three times in 2007 and 2008 during the LAR creation process. The first meeting was used to meet formally with the staff and gain the NRC's input on the best method to prepare the Monticello LAR. The second two meetings were devoted to steam dryer analysis methodologies. The NRC did not raise any significant technical concerns in response to our presentations. Unfortunately, our due diligence and preparatory efforts did not take into account the number of changes the NRC was making to the regulatory requirements, or the NRC's conservative cultural shift, which was further exacerbated by the Fukushima incident.

Licensing Calculation Requirements. One of the more noteworthy requirements that impacted the overall EPU licensing efforts was the revision to our calculation fleet procedures after issues were raised during an NRC Region III inspection. The change resulted in a threefold increase in the amount of work necessary to complete approximately 500 major calculations. In addition, a substantial increase in the total population of calculations occurred from the 1998 uprate, and this calculation procedure change resulted in the need to perform a complete reconstitution of the HELB, MOV, AOV and EQ programs and substantial changes associated with instrument setpoint methodologies. The cost associated with a significant portion of the calculation work was tracked in five work orders as follows:

Project Modification	Work Order	Final Costs
High Energy Line Break	11636097	$4,778,454
Environmental Qualification	11636101	$2,522,236
Instrument Service Requirements	11636105	$2,144,441
Motor and Air Operated Valves	11636109	$2,582,437
Stress Analysis for Piping	11636114	$4,052,729
Total Cost (without AFUDC & RWIP)		**$16,080,297**

We were required to comply with all of the NRC requirements for providing additional calculations. The strategy we employed for this issue was to revise the calculations to meet the regulatory quality requirements. Note that the Company attempted to use internal resources to the extent possible for conducting these required calculations to minimize the added cost.

Developments at Other Plants – Steam Dryer. A principle concern arose immediately after our submission that led to our withdrawal of the EPU LAR. In March 2008, approximately two weeks before we submitted our initial LAR, the ACRS effectively requested an increase in the level of scrutiny for the steam dryer structural analysis by increasing the minimum margin threshold to 2.0. As described in the testimony of Mr. O'Connor, experience at other plants led to the NRC concerns about our plans regarding the Steam Dryer. Most noteworthy, following its uprate, in 2003 Quad Cities Unit 1 experienced steam dryer cracking, which progressed to the point that pieces of the steam dryer hood separated from the dryer and entered the steam line system. Vermont Yankee also required considerable attention due to crack indications discovered during a detailed inspection associated with an EPU approved in 2006. These experiences at other facilities caused the NRC to require detailed structural analysis of the steam dryer before approving an EPU. Ultimately, based on these events at other plants, we decided to replace rather than modify the existing steam dryer, which resulted in project costs of $31 million for the dryer, and approximately $3.5 million for repairs to strain gauges used to monitor steam dryer loads, repairs to accelerometers used to monitor piping vibration, and removal of steam dryer instrumentation. (Documents supporting this analysis will be produced in response to Information Request DOC-50 and more specifically in folders designated for NRC issues and IR DOC-62).

The steam dryer developments were the primary driver of the need to resubmit the LAR application in October 2008, after the NRC notified us that our first application was inadequate with respect to our steam dryer integrity analysis. During the four months between withdrawal of the initial LAR and re-submittal, the Company undertook additional analysis and other work to address the three deficiencies identified by the NRC staff. While we did not track costs specifically associated with the need to resubmit the LAR, we estimate that incremental effort expended during those four months amounted to approximately $4 million. During the five years the LAR was pending, the NRC has requested the Company provide six separate analyses of the steam dryer. Each of these efforts required considerable effort by our internal and external resources and increased our licensing costs by about $3 million.

We considered three factors when we decided to modify, and not replace, the existing steam dryer during our Project study phase in 2006-2007: (1) the benchmarking of other EPUs; (2) GE's initial assessments (in its scoping evaluations in 2004 and 2006, GE recommended Xcel Energy either modify or replace the steam dryer for EPU); and (3) cost control.

As noted above, we met with the NRC three times before we submitted our initial LAR and the NRC raised no issues with our proposed steam dryer modifications and analyses. After we withdrew the initial LAR, we consulted a vendor with specific steam dryer experience, and it became increasingly clear that replacement of the steam dryer was necessary to mitigate the risk to the LCM/EPU Program schedule that could result from regulatory delays. As a result of those perceived risks, the Company elected to procure a replacement steam dryer, and ultimately chose Westinghouse. Xcel Energy met with the NRC again in October 2008 to discuss our proposed approach to address the steam dryer issue identified in our initial LAR submission, and we resubmitted the EPU LAR to the NRC on November 5, 2008. We notified the NRC of the intent to install a new steam dryer on February 18, 2010. See L-MT-10-007.

Industry Developments – Containment Accident Pressure (CAP). Monticello was approved to use CAP credit under our license basis and we used these requirements in our LAR submission. Our analysis showed that our operations would remain within the original requirements at uprate conditions with no additional NRC approval. Our approach was consistent with the approach of other utilities seeking EPU approval and CAP credit was granted by the NRC in earlier EPU LARs.

Shortly after we submitted the LAR in November 2008, use of CAP in determining the available Net Positive Suction Head was challenged by the ACRS, by participants in the NRC hearing process, and members of the public, who raised the possibility that the practice of using CAP credit could result in the degradation of the regulatory defense-in-depth philosophy. In March 2009, the ACRS recommended industry-wide changes to the practice of including CAP credit in NRC-approved licenses until resolution of areas of disagreement between the staff and the ACRS could be obtained. In October 2009, the NRC officially informed the Company that the agency required more time to ensure the technical adequacy of the Company's application, which would result in delays in the staff's review of the application.

The Company worked diligently to move the issue forward, and did so successfully just as the events of Fukushima unfolded. The CAP issue changed quickly after that date and the NRC staff indicated it would need significant additional analysis of the ECCS pumps and more review time to assure appropriate resolution of this issue. In March 2011, the NRC added a new set of analytical requirements to determine the ECCS pump NPSH uncertainties and in April 2011, the NRC officially reactivated the review of the EPU LAR. In total, the CAP issue delayed NRC approval of the LAR by approximately four years.

The CAP analysis requirement was new to the entire industry and had never been implemented before. Monticello was the lead plant that had to develop and implement a computationally complex resolution. We pursued parallel paths to ensure a successful outcome, working collaboratively with the rest of the industry in the BWROG, and also on its own independent analytical approach. To prepare the NPSH uncertainty analysis, in July 2011, the BWROG retained a vendor to perform computational fluid dynamics evaluation of industry ECCS pumps. The CFD model was constructed of 15 million elements and required the use of up to several hundred computers running iterations simultaneously. In March 2012, the BWROG determined that the use of the CFD model to test the ECCS pump design was not feasible.

Simultaneous with the BWROG efforts, Monticello worked to develop an analysis to support the use of CAP and satisfy all NRC requirements. The analysis we developed supported the continued safety and reliability of the ECCS pumps under all accident and event conditions. We submitted those analyses to the NRC in September and November 2012, and we responded to additional CAP RAIs in February and March 2013. The NRC approved our CAP analysis in 2013, marking the first time the industry has successfully addressed the CAP issue under the new NRC guidelines. Throughout the NRC's extensive consideration of the CAP issue that delayed approval of the LAR, we worked closely with the NRC and industry working groups to minimize the impact and develop a working solution.

Back-Fit/Forward-Fit Requirements. An EPU opens a nuclear facility to regulatory 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. Because an EPU affects so many plant components, an EPU LAR opens the licensee to questions about many aspects of the plant's current licensing basis and expectations from regulatory staff and other stakeholders that the licensee will upgrade various plant components not only to meet the operational requirements of the higher power levels following the EPU, but also safety standards that may have evolved since the plant was originally licensed, despite protections against back-fitting. The staff's position is that truly voluntary license amendments are not subject to the backfit rule and therefore the application of new or different staff positions are appropriate. See NRC Letter to Nuclear Energy Institute, July 14, 2010.

Changes to the NRC's requirements in steam dryer analysis were implemented for the Monticello EPU LAR under this forward-fit concept based on industry experiences, as described above.

We also installed the Power Range Neutron Monitor (PRNM) as part of the LCM/EPU Project to meet the NRC's forward-fit application of the core monitoring requirements for MELLLA+. We determined installation of the PRNM was required to meet the NRC's concerns in this area. The final cost of the PRNM modification was $17.5 million (work order 10942850). Our primary mitigation was to assure that the monitor was installed with a solid design to avoid startup problems that had occurred at other plants and the project was successful in that regard.

The NRC changed its view of EPU licenses to include requiring upgrading plant designs, analysis codes to address industry issues that under the old license were acceptable as is. The best example of this is the containment accident pressure issue but there are others. Another example was recent treatment of multiple spurious hot shorts under the fire protection program. The previous license required consideration of one hot short while for the EPU CAP analysis this number was changed to four hot shorts.

Aging Management Requirements (AMR). 10 CFR Part 54 contains the NRC's requirements for renewing the operating license of a commercial nuclear power plant and requires applicants for a license renewal to identify the structures and components that must undergo an AMR evaluation. The rule further requires all licensees to perform analyses to predict the end of the useful life of the components and perform component replacement and maintenance to ensure the components will be capable of performing the intended function for the remainder of the extended license period.

Because the AMR requirements include numerous analyses to demonstrate the capability of a large number of structures and components to perform their intended safety functions, Xcel Energy was forced to so expend significant effort to complete these analyses to support the LAR submittal. Although we did not track incremental costs attributable to AMR requirements, we believe they had a significant impact on our licensing and overall Project costs.

We performed vigorous analysis and inspections of the current condition of the structures and components subject to the NRC's AMR to determine if those items might require replacement or refurbishment, consistent with our obligation to protect the health and safety or our workers and customers.

Maintenance Rule Requirements. Similar to the AMR, Xcel Energy must monitor the performance of the structures, systems and components and refurbish or replace the components when necessary to ensure all aspects of the plant are capable of performing their intended safety function. See 10 C.F.R. 50.65. An example of the Maintenance Rule impact on the LCM/EPU is the replacement of the torus water level instruments. The Maintenance Rule analysis on this system led to the need to replace certain instruments that monitor the level of the water within the torus. We did not track the costs incurred as a result of the Maintenance Rule Requirements but recognize that such costs impacted the final Project costs.

Consistent with our approach to AMR, we vigorously analyzed and inspected the current condition of the SSCs subject to the Maintenance Rule and to the extent we determined replacement was required, after validation of our analysis, we negotiated intensely with our vendors to lower the cost of the additional scope without impeding progress on the LCM/EPU Project.

Fukushima. We believe that the evolving regulatory requirements and the need to proactively manage our operating margins increased after the Fukushima incident. As mentioned above, Fukishima led to a more thorough review of our plan to comply with Containment Accident Pressure credit included in our licensing costs. The additional analysis was likely to be required at some point but in order to keep the license process moving we spent more for the BWROG work than would have been the case had a defense in depth process change been permitted. In addition the delay in approval led to additional RAIs that occurred as the license process extended through several staff changes. The NRC staff response to the anticipated defense in depth approach we believe was influenced by the events at Fukishima.

Also, as we noted in prior testimony, the impacts of Fukishima, particularly as it relates to electric margin, made the decision surrounding the 13.8kV upgrade much more related to Life Cycle Management given the current electric loads already on the system and the fact that new electric loads will need to be added even in the absence of the power uprate. The damage at Fukushima has increased emphasis on all aspects of power reliability, as one of the most critical factors in providing plants with adequate safety margin. The plant's original 4kV design would be undersized for the motor operating margin requirements in today's regulatory environment. The lack of reliability margin in the 4kV system necessitated upgrade and replacement of its supporting components such as transformers and switch gear. The 13.8kV work was not included in the original design and could not have been predicted in our initial cost estimates, but it is needed for Monticello's continued operations.

Preparer: Steve Hammer
Title: Licensing Project Manager
Department: Nuclear
Telephone: 763-295-1300
Date: March 13, 2014

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☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	75
Requestor:	Nancy Campbell/Chris Shaw		
Date Received:	March 27, 2014		

Question:

Please provide detailed information explaining the Containment Accident Pressure (CAP) issue.

Response:

As discussed in our combination Response to DOC Information Requests 59/60/62, the Company was approved to use CAP under the pre-EPU license basis and included CAP license basis in our EPU LAR submittal. Subsequently, the use of CAP was challenged by the Advisory Committee on Reactor Safeguards (ACRS).

All nuclear facilities have a number of systems that provide cooling to the reactor core following a reactor accident. The systems are identified in the facility's licensing basis. These diverse high and low pressure systems inject cooling water to keep the reactor core covered with water and are referred to as the ECCS systems (emergency core cooling systems).

Reactor design relies on defense-in-depth to protect the health and safety of the public from any radioactive releases. These defense-in-depth systems include three primary components: (1) the immediate cladding around the nuclear fuel; (2) the integrity of the primary coolant system; and (3) the primary containment boundary. If the primary coolant system were breached, water and steam would be released into the primary containment. In our pre-EPU licensing basis, Monticello (along with many other facilities) relied on the primary containment pressures generated by this steam to provide the net positive suction head (NPSH) necessary to operate the ECCS pumps and maintain the core cooling requirements. Monticello was one of nearly 30 plants that relied on this post-accident containment pressure to maintain NPSH. Specifically, Monticello relied on pressure inside containment for up to 84 hours with a peak pressure of 5.7 psig required for a short time period. The NRC approved the use of up to 6.1 psig to support ECCS pump operation.

In BWRs, EPUs increase the temperature of the water contained within the suppression pool during certain postulated accidents or abnormal events. This higher temperature could affect the ability of the ECCS pumps to operate effectively (i.e., to cool the reactor core and containment). CAP credit refers to the reliance in safety analyses on the use of a portion of the pressure in the primary containment to demonstrate acceptable performance of the ECCS pumps. CAP credit assumes that containment integrity has been maintained.

Monticello was approved to use CAP under the pre-EPU license basis and we included these CAP license basis requirements in the November 1, 2008, LAR submission. Our analysis showed that at uprate conditions our operations would remain within the original requirements with no additional NRC approval. Specifically we were able to demonstrate that we would rely on a peak pressure of 6.01 psig with reliance on CAP for up to 49 hours at higher rated power under EPU conditions. Since this remained within the NRC's already approved limits, no specific additional approvals were anticipated.

At the time the Company was preparing the EPU LAR, other utilities were handling this issue in a similar fashion. Additionally, the NRC granted CAP credit in earlier EPU LARs. Consistent with the guidance that the licensing requirements would not change with a LAR, the CAP credit analysis for Monticello was performed consistent with previously approved licensing requirements. The most recent NRC review in this area had been completed under Amendment No. 139 to Facility Operating License on June 2, 2004.

The ACRS has been concerned with industry reliance on CAP post-accident and reduction in margin for the defense-in-depth concept since 1997.[1] Generally, however, the NRC staff did not share the ACRS' concerns, and did not request existing licensees to backfit modifications to remove existing CAP reliance.

Shortly after our LAR submission, use of CAP in determining the available NPSH was again challenged by the ACRS, by participants in the NRC hearing process, and by members of the public. Published regulatory guidance allowing the use of CAP in

[1] The ACRS was established as a statutory committee with the passing of the Price-Anderson Bill in 1957. The ACRS functions as an independent advisory board to the NRC Commissioners. The ACRS has a significant role in the review and resolution of key technical issues associated with regulation of nuclear power plants. The ACRS is made up of leading industry and academic specialists and it reviews all recommendations for license renewal and uprate, in addition to other areas.

determining NPSH was not consistent with the issues noted by the groups above. The practice was also thought to result in degradation of the regulatory philosophy of defense-in-depth (independence of fission product barriers) by the ACRS. For these reasons, the NRC staff determined that it would reexamine the issue.

Following our submittal of the Monticello EPU LAR, a March 2009 letter from the NRC to the ACRS recommended industry-wide changes to the practice of including CAP credit in NRC-approved licenses until resolution of areas of disagreement between the staff and the ACRS could be obtained. The discussion included the ACRS's view that CAP should be limited in amount and duration. The ACRS recommended that licensees requesting it should be required to demonstrate that it is not practical to reduce or eliminate the need for CAP. See Attachment A to this response for a copy of the ACRS letter dated March 18, 2009.

This letter and subsequent consideration of the CAP issue by NRC staff and commissioners led to a year and one-half delay in the NRC's review of Monticello's EPU LAR. In October 2009, the NRC officially informed the Company that the agency required more time to develop additional regulatory guidance to ensure the technical adequacy of the Company's application, which would result in delays in the staff's review of the EPU LAR application. See Attachment B to this response for a copy of the NRC letter dated October 1, 2009.

The Commission put the EPU LAR on hold until disagreements between the NRC staff and the ACRS could be resolved. In March 2010, the Office of Nuclear Reactor Regulation (NRR)[2] issued draft CAP guidance to the Boiling Water Reactor Owner's Group (BWROG). In May 2010, the ACRS issued its conclusions and recommendations regarding the NRR draft guidance for crediting CAP in meeting NPSH required to demonstrate that safety systems could mitigate accidents as designed. The ACRS recommended that licensees must first demonstrate that it would be impractical to make plant modifications that eliminate the need for CAP (overpressure). In June 2010, the NRR responded to the ACRS recommendations and notified the Company that the EPU LAR would remain deferred until the issue was fully resolved. See Attachments C, D and E to this response for copies of the NRC letter dated March 1, 2010, the ACRS letter dated May 19, 2010 and the NRR response letter dated June 10, 2010, respectively.

[2] The NRR is a subordinate part of the NRC responsible for accomplishing key components of the NRC's nuclear reactor safety mission. As such, NRR conducts a broad range of regulatory activities in the four primary program areas of rulemaking, licensing, oversight, and incident response for commercial nuclear power reactors, and test and research reactors to protect the public health, safety, and the environment.

The Company worked diligently to move this issue forward, and did so successfully just as the events of Fukishima unfolded. An issue that we believed we had reached consensus on with the NRC and its Staff changed quickly after the Fukishima incident, as the final NRC Staff Guidance indicated that significant additional analysis of the ECCS pumps and more review time to assure appropriate resolution of this issue would be required.

In January 2011, the NRC staff issued SECY11-0014, Use of Containment Accident Pressure in Analyzing Emergency Core Cooling System and Containment Heat Removal System Pump Performance in Postulated Accidents, which provided various options for consideration of the use of CAP. On March 15, 2011, the NRC commissioners voted to approve the staff's recommendation to resume reviews of EPU applications and add a new set of analytical requirements to determine the ECCS pump NPSH uncertainties. By letter dated April 5, 2011 (ML11081A046), the NRC officially reactivated the review of Monticello's EPU LAR.

The new CAP analysis requirements presented unique licensing challenges. Because the CAP analysis requirement was new to the entire industry, it had never been implemented before. Therefore, Monticello was the lead nuclear power plant that had to develop and implement a computationally and analytically complex issue to define pump performance uncertainties.

Monticello pursued parallel paths to ensure a successful outcome, working collaboratively with the rest of the industry on the BWROG and also on its own independent analytical approach. As discussions progressed at the Company concerning the new guidance in SECY 11-0014, it became clear that the Company needed to work with industry resources to solve the technical issues raised.

Monticello personnel were involved in the BWROG effort to resolve the new CAP requirements. In July 2011, to prepare the NPSH uncertainty analysis, the BWROG retained a vendor to perform computational fluid dynamics (CFD) evaluation of industry ECCS pumps to define the pump performance uncertainties. The CFD model was constructed of 15 million elements. Each simulation was run at up to four different flow rates. To reach convergence at a given flow rate several iterations were typically required with each iteration requiring from days to weeks to reach completion even with the use of a parallel array of up to several hundred computers to reach a solution.

By March 2012, the BWROG determined that the use of computational fluid dynamics to model the Monticello ECCS pump design was not feasible. Five attempts were made to develop an acceptable model but none were successful. In

April 2012, BWROG representatives met with the NRC to discuss these results and develop an alternative approach for assessment of pump uncertainties. The alternative approach resulted in need for the development of six modified Task Reports to address required areas of study related to NPSH uncertainty and pump reliability. The BWROG submitted the Task Report results to the NRC in October 2012.

The Company used the BWROG Task Reports to develop an analysis to support our position that the use of CAP met all NRC requirements. The analysis supported the continued safety and reliability of the ECCS pumps under all accident and event conditions. We submitted those analyses in September and November 2012, and we responded to additional CAP RAIs in February and March 2013. Monticello's approach to CAP was approved by the ACRS on September 6, 2013. That approval marked the first time the industry has successfully addressed the CAP issue under the requirements of SECY 11-0014.

Preparer: Steve Hammer
Title: Licensing Project Manager
Department: Nuclear
Telephone: 763-295-1300
Date: April 8, 2014

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

March 18, 2009

Mr. R.W. Borchardt
Executive Director for Operations
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: CREDITING CONTAINMENT OVERPRESSURE IN MEETING THE NET POSITIVE SUCTION HEAD REQUIRED TO DEMONSTRATE THAT THE SAFETY SYSTEMS CAN MITIGATE THE ACCIDENTS AS DESIGNED

Dear Mr. Borchardt:

In the January 8, 2009, Staff Requirements Memorandum [Ref. 1], the Commission directed the staff, in part, to continue working to resolve the difference of opinion with the Advisory Committee on Reactor Safeguards on the containment overpressure (COP) credit issue. During our 559th, February 5-7, 2009, and 560th, March 5-7, 2009, meetings, we discussed the acceptability of the use of COP and the types of supporting analyses and additional information that are needed in our view to determine the acceptability of COP credit in extended power uprate (EPU) applications. This letter report is intended to facilitate the resolution of the COP credit issue.

CONCLUSIONS AND RECOMMENDATIONS

1. To preserve safety margin in all reactors, credit for COP should be limited in amount and duration. Licensees requesting such credit should continue to be required to demonstrate that it is not practical to reduce or eliminate the need for overpressure credit by hardware changes or requalification of equipment.

2. Licensees should continue to be requested to use the current guidance in Regulatory Guide 1.82 Revision 3 [Ref. 2] and the licensing-basis analyses assumptions and methods to demonstrate that the available net positive suction head (NPSH) exceeds that required for operation of the emergency core cooling system (ECCS) and containment heat removal pumps.

3. Regulatory Guide 1.82 Revision 3 [Ref. 2] should be revised to request that licensees submit additional analyses and information if the amount of accident pressure that must be credited based on the licensing-basis analyses is not a small fraction of the total containment accident pressure and limited in duration. The additional information should include thermal-hydraulic analyses, which address the conservatisms associated with the licensing-basis analyses and explicitly account for uncertainties and probabilistic

risk assessment (PRA) results consistent in scope and quality with that specified by Regulatory Guide 1.174 [Ref. 3].

4. For cases in which operator actions are required to maintain containment overpressure, licensees should show how these actions can be implemented in their procedures, that they can be performed reliably, and that any increase in risk associated with these actions is acceptably small.

5. The staff review guidance in the current Standard Review Plan (SRP) [Ref. 4] should be revised to state that, if COP credit is granted to a plant based on risk information, all subsequent licensing applications involving COP credit at that plant should also include risk information.

BACKGROUND

For most U.S. nuclear plants, NPSH for ECCS pumps in licensing basis analyses is calculated assuming that the pressure in containment is atmospheric. In reality, accidents such as loss of coolant accident (LOCA) would lead to an increase in containment pressure. The assumption of atmospheric pressure assured that in design-basis accidents the loss of COP for any reason would not affect the ability of the ECCS to maintain core cooling. This maintained the defense-in-depth philosophy of the independence of accident prevention and mitigation. The containment pressure generated by the accident is part of the safety margin against loss of NPSH. Such margin protects against unanticipated accident phenomena such as sump strainer blockage.

The inclusion of the pressure developed in the containment during an accident in the calculation of the available NPSH is referred to as COP credit. Since 1997, the ACRS expressed concerns over the crediting of COP in NPSH calculations in a series of reports [Refs. 5, 6, 9, 10, and 11]. In a report dated June 17, 1997 [Ref. 5], the ACRS stated that containment overpressure credit should not be granted. In the December 12, 1997, [Ref. 6] report, the Committee concluded that granting credit for small amounts of COP may be acceptable in some cases.

DISCUSSION

Licensees are now seeking to use the margin associated with the pressure generated in the containment during an accident to support voluntary licensing actions such as extended power uprates (EPUs). In some cases, the licensing-basis analyses supporting the EPU show that the requested COP credit is significant in amount and duration and that the pumps may cavitate for some time even with full credit for available overpressure. Although pump vendors are requested to verify that the pumps can operate under these conditions without failing and tests are done to demonstrate this capability, the pumps are being operated outside their design specifications. In order to maximize available overpressure, operators may also be directed to undertake actions, such as termination of drywell cooling, that are contrary to the actions usually expected in response to an accident.

Northern States Power Company

The ACRS has consistently expressed concern with the use of this margin for voluntary licensing actions because it represents a decrease in the safety margin available to deal with a phenomenon subject to large uncertainties, namely, maintenance of adequate NPSH for ECCS pumps during accidents. The margin in this case is not against plastic deformation of some component or the failure of a few fuel rods, but potential melting of the core. It also challenges the defense-in-depth philosophy. Containment integrity is now not only the final barrier to prevent release of fission products, but is also required to prevent core damage.

In most operating plants, all of the pressure generated during an accident is part of the safety margin against loss of NPSH in the ECCS pumps. To preserve this safety margin in all plants, COP credit should be limited in amount and duration. The amount of accident-generated pressure credited should only be a small fraction of that expected to be available.

We also have concerns regarding requests for COP credit requiring operator actions to establish or maintain elevated containment pressure for adequate pump NPSH, irrespective of the amount or duration of these conditions. Of particular concern are actions that stop or reduce operation of systems whose normal design function is to remove heat from the reactor core or containment.

The current guidance in Regulatory Guide 1.82, Revision 3 focuses on the conservative calculation of containment pressure for licensing-basis accidents and imposes no limits on the amount and duration of credit as long as these calculations show that the available NPSH is greater than that required for operation of the pumps. Since 2005, the guidance for the staff's review of requests for additional COP credit associated with EPU has included a risk review based on Appendix D of SRP Section 19.2. There is some question as to the scope and quality of risk information that the staff can request under this guidance. The PRA information for EPUs in which substantial amounts of COP credit are requested based on licensing-basis analyses should be of scope and quality consistent with Regulatory Guide 1.174.

The staff contends that the significant conservatism included in the LOCA analyses provides adequate margin. Also, for special events, which are analyzed with less conservative thermal-hydraulic assumptions, a reasonable level of safety is maintained because of the other conservatisms in the analyses. Although it is true that the licensing-basis analyses currently submitted by licensees to justify COP credit are based on conservative input assumptions, it is difficult to assess the degree of conservatism and hence the impact on margin against loss of NPSH associated with these analyses.

We agree with the staff that a conservative calculation of containment pressure for licensing-basis accidents that shows that the available NPSH is greater than that required for operation of the pumps is a necessary condition for COP credit. We also agree that, if COP credit is requested, the licensee should be requested to submit an explanation of why hardware changes or requalification cannot be practicably implemented that would eliminate or reduce the need for COP credit. In our view, if hardware changes are impractical but the licensing-basis analyses show that the amount and duration of credit are "small" and operator actions to maintain containment overpressure are not introduced, no further analyses need be required.

If hardware changes are not practical and the requested amount and the duration of COP credit are not "small" or operator actions are introduced, Regulatory Guide 1.82 should be revised to request that the licensee provide additional analyses and/or tests to help understand the impact on safety margins and defense in depth of granting COP credit. Such analyses could include more realistic evaluations of LOCA scenarios with treatment of uncertainties; alternate, more realistic fire analyses for Appendix R scenarios; identification of the particular single failures that lead to the need for COP credit; estimates of conditional changes in core damage frequency (CDF) if required COP credit were not available (an importance measure for COP credit); and pump tests to show the capability of ECCS pumps to function with cavitation. The staff should review this information along with the results of licensing-basis analyses.

The number and detail of the additional analyses would depend on the amount and duration of the requested COP credit and the nature of any operator actions credited in maintaining the required containment pressure. These analyses should provide more realistic estimates of the amount and duration of credit actually needed, the likelihood of scenarios that would require substantial COP credit, and the reliability of, and potential problems associated with operator actions.

Irrespective of the amount and duration of requested COP credit, if operator actions to increase or maintain elevated containment pressure are required, an integrated assessment should be performed to examine the specific accident scenarios that require operator intervention. The assessment should quantify the frequency of each scenario and evaluate the reliability of the required actions for expected plant conditions. The assessment should also identify and evaluate situations in which unexpected consequences from these actions could result in increase in risk. Explanations should be provided of how these actions are addressed in operating procedures, whether they are consistent with an applicant's current design and licensing bases, and what evidence is available that they can be performed reliably.

The PRA information associated with the review is important not only to ensure that the risk is small, but also to help assess the impact of the credit on defense in depth. Current PRAs can estimate the likelihood of pre-existing containment leakage. They typically do not evaluate the likelihood of relatively small amounts of leakage or other evolving conditions that might reduce the available NPSH. However, PRAs could be used to investigate the likelihood of scenarios in which large amounts of COP credit are needed for significant amounts of time and thus could be used to help judge the impact of the credit on defense in depth.

Unlike the position of Regulatory Guide 1.1, [Ref. 12] or the previous staff position based solely on licensing-basis analyses, the judgment whether to grant COP credit for a particular application would depend on an integrated decisionmaking process that considers the more realistic, available estimates of the amount and duration of COP credit required; the likelihood of scenarios that would require COP credit; and the operator actions required to maintain COP for adequate pump NPSH.

The current staff guidance in Appendix D to SRP Section 19.2 includes a risk review for COP credit only for EPU applications. This current staff guidance should be revised to state that, if

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COP credit is granted based on risk information, all subsequent licensing applications involving COP credit should also include risk information.

We look forward to working with the staff on these important matters.

Sincerely,

/RA/

Mario V. Bonaca
Chairman

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1. U.S. Nuclear Regulatory Commission, Staff Requirements Memorandum, “Meeting with Advisory Committee on Reactor Safeguards (ACRS),” January 8, 2009, (ML090090338)

2. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.82, Revision 3, “Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident,” November 2003 (ML023100171)

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4. U.S. Nuclear Regulatory Commission, NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition,” Section 6.2.2, Containment Heat Removal Systems, Revision 5, March 2007; http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr0800/

5. Letter from R. L. Seale, ACRS Chairman, to L. Joseph Callan, NRC Executive Director for Operations, Subject: Proposed Final Generic Letter, “Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps,” June 17, 1997

6. Letter from R. L. Seale, ACRS Chairman, to S. A. Jackson, NRC Chairman, Subject: “Credit for Containment Overpressure to Provide Assurances of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps,” December 12, 1997

7. Letter from Joseph Callan, NRC Executive Director for Operations, to R. L. Seale, ACRS Chairman, Subject: Proposed Final Generic Letter, “Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps,” June 17, 1997

8. Memorandum from John T. Larkins, ACRS Executive Director to L. Joseph Callan, NRC Executive Director for Operations, Subject: Proposed Final Generic Letter, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," June 17, 1997

9. Report from Graham B. Wallis, ACRS Chairman, to Luis A. Reyes, NRC Executive Director of Operations, Subject: Proposed Revision 4 to Regulatory Guide 1.82, "Water Sources for Long-Term Recirculation Cooling Following A Loss-of-Coolant Accident," September 20, 2005 http://www.nrc.gov/reading-rm/doc-collections/acrs/letters/2005/5252146.pdf

10. Report from Graham B. Wallis, ACRS Chairman to Nils J. Diaz, NRC Chairman, Subject: "Vermont Yankee Extended Power Uprate," January 4, 2006

11. Report from William J. Shack, ACRS Chairman to Dale Klein, NRC Chairman, Subject: "Browns Ferry Nuclear Plant, Unit 1, 5-Percent Power Uprate," February 16, 2007

12. U.S. Nuclear Regulatory Commission, Safety Guide 1.1 *(Regulatory Guide 1.10),* "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps," November 1970

8. Memorandum from John T. Larkins, ACRS Executive Director to L. Joseph Callan, NRC Executive Director for Operations, Subject: Proposed Final Generic Letter, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," June 17, 1997

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 1, 2009

Mr. Timothy J. O'Connor
Site Vice President
Monticello Nuclear Generating Plant
Northern States Power Company - Minnesota (NSPM)
2807 West County Road 75
Monticello, MN 55362-9637

SUBJECT: MONTICELLO NUCLEAR GENERATING PLANT – REVISED SCHEDULE FOR REVIEW OF EXTENDED POWER UPRATE AMENDMENT APPLICATION (TAC NO. MD9990)

Dear Mr. O'Connor:

This letter is to inform you of the decision of the U.S. Nuclear Regulatory Commission (NRC) to delay the review of the Monticello Nuclear Generating Plant (MNGP) extended power uprate (EPU) application dated November 5, 2008. As you are aware, in a staff requirements memorandum dated January 8, 2009, the Commission directed the Office of Nuclear Reactor Regulation (NRR) staff to continue to work towards resolving Advisory Committee on Reactor Safeguards (ACRS) concerns regarding the application of containment accident pressure (CAP) credit.

On March 18, 2009, the ACRS issued a letter providing recommendations to facilitate resolution of its CAP concerns. In response, the NRC staff wrote to the ACRS on June 4, 2009, stating that "[w]hile the staff carefully weighs the ACRS recommendations, we may consider delaying issuance of licensing actions currently under review related to changes in the use of containment accident pressure." The NRR staff has reviewed all the proposed options and the ACRS' recommendations. As was discussed with your staff on September 15, 2009, the NRC staff has determined that additional time is warranted to develop additional review criteria to ensure the technical adequacy of the MNGP EPU application. The development of this review criteria is essential to provide the technical and regulatory consistency, as well as the schedule certainty needed to complete this review.

Therefore, the NRC staff will focus on closing out the other outstanding technical issues associated with the MNGP EPU amendment application. When appropriate review criteria have been completed, the NRC staff will discuss with your staff the remaining information needed to support completion of the EPU review.

As indicated during the conference call, it is expected that the review criteria will be available in the spring of 2010.

Should you have any questions, please feel free to contact the Monticello Project Manager, Mr. Peter Tam at (301) 415-1451.

Sincerely,

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Docket No. 50-263

cc: Listserv

T. O'Connor - 2 -

As indicated during the conference call, it is expected that the review criteria will be available in the spring of 2010.

Should you have any questions, please feel free to contact the Monticello Project Manager, Mr. Peter Tam at (301) 415-1451.

Sincerely,

/RA by J Wiggins for/

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Docket No. 50-263

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Northern States Power Company

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

May 19, 2010

Mr. R.W. Borchardt
Executive Director for Operations
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: DRAFT GUIDANCE ON CREDITING CONTAINMENT ACCIDENT PRESSURE IN MEETING THE NET POSITIVE SUCTION HEAD REQUIRED TO DEMONSTRATE THAT SAFETY SYSTEMS CAN MITIGATE ACCIDENTS AS DESIGNED

Dear Mr. Borchardt:

In a January 8, 2009, Staff Requirements Memorandum, the Commission directed the staff, in part, to continue working to resolve the differences of opinion between the Advisory Committee on Reactor Safeguards and the staff on the containment accident pressure (CAP) credit issue. At the April 23, 2010, meeting of our Subcommittee on Power Uprates and our 572nd meeting on May 6-8, 2010, we discussed the draft guidance the staff is developing to determine the acceptability of CAP credit for extended power uprates (EPUs) and other applications. The Subcommittee also discussed the Boiling Water Reactor Owners Group (BWROG), Licensing Topical Report NEDC-33347P, "Containment Overpressure Credit for Net Positive Suction Head (NPSH)," that is intended to provide a more standardized and predictable approach for use by applicants to request credit for CAP in computing available NPSH. In addition to the discussions with NRC staff and industry representatives, we also had the benefit of the documents referenced.

CONCLUSIONS AND RECOMMENDATIONS

1. We agree with the staff that, before considering analyses to justify credit for containment accident pressure to maintain available NPSH for emergency core cooling system (ECCS) and containment heat removal pumps, licensees must first demonstrate that it is impractical to make plant modifications that eliminate this need. However, we disagree with the staff's position that a generic waiver of this requirement is appropriate for BWRs with Mark I containments. Any waiver should be evaluated on a plant-specific basis.

2. The draft guidance developed by the staff provides an improved framework for a more comprehensive assessment of the acceptability of crediting containment accident pressure in meeting NPSH requirements. However, the guidance is primarily focused on the deterministic analysis of licensing-basis events. These analyses should be complemented by plant-specific Probabilistic Risk Assessment (PRA) analyses of the impact of CAP credit.

3. We support the staff's reassessment of the potential problems associated with the operation of pumps with available NPSH near or below the required NPSH for the pump.

4. For calculations involving design basis loss-of-coolant accidents (LOCAs), we agree with the position of the BWROG that statistical calculations should be performed to better understand margins and more accurately characterize the potential for pump damage. In most cases, the licensing decision should be based on the conservative, deterministic calculation of available NPSH. In all cases, the comparison of available NPSH with required NPSH should include consideration of the uncertainty in the required NPSH as proposed by the staff in the draft guidance.

5. If no CAP credit is needed for the special events licensing-basis analyses, and the 95/95 lower tolerance bound for LOCAs calculated using an acceptable methodology shows that no CAP credit is needed, then the CAP credit can be deemed small enough that it is acceptable without the need for hardware modifications or additional risk studies.

6. The PRA studies by the staff are helpful in assessing the importance of pre-initiator and post-initiator leak probability and leakage test interval on the changes in risk associated with CAP credit. The seismic studies provide useful order-of-magnitude estimates. Seismic events, fires, and operator actions are potentially significant risk contributors. It is not possible to adequately assess these risks except on a plant-specific basis.

BACKGROUND

For most U.S. nuclear plants, NPSH for ECCS pumps in licensing-basis analyses is calculated assuming that the pressure in containment is atmospheric. In reality, accidents such as a LOCA would lead to an increase in the containment pressure. The assumption of atmospheric pressure in the containment assures that in design-basis accidents, the loss, for any reason, of the capability of the containment to maintain pressure would not affect the ability of the ECCS to maintain core cooling. This assumption maintains the defense-in-depth philosophy for accident prevention and mitigation and the independence of barriers. In addition, in most operating plants, all of the pressure generated during an accident is part of the safety margin against loss of NPSH in the ECCS pumps.

The inclusion of the pressure developed in the containment during an accident in the calculation of the available NPSH is referred to as CAP credit. We have consistently expressed concern with the use of this margin for voluntary licensing actions because it represents a decrease in the safety margin available to deal with a phenomenon that is subject to large uncertainties, namely, maintenance of adequate NPSH for ECCS pumps during accidents. Such margin protects against unanticipated accident phenomena, such as sump strainer blockage or an inadvertent loss of containment isolation. In some requests for CAP credit, operator actions are required to establish or maintain elevated containment pressure in order to attain adequate pump NPSH. Of particular concern are actions that stop or reduce operation of systems whose normal design function is to remove heat from the reactor core or containment.

The staff has also recognized that use of CAP credit compromises the independence of barriers. The first Regulatory Guide published in 1970 as Safety Guide 1.1 addressed this issue and stated:

> *It is important that the proper performance of emergency core cooling and containment heat removal systems be independent of calculated increases in containment pressure*

Northern States Power Company

> *caused by postulated loss of coolant accidents in order to assure reliable operation under a variety of possible accident conditions. For example, if proper operation of the emergency core cooling system depends upon maintaining the containment pressure above a specified minimum amount, then too low an internal pressure (resulting from impaired containment integrity or operation of the containment heat removal systems at too high a rate) could significantly affect the ability of this system to accomplish its safety functions by causing pump cavitation. In addition, the deliberate continuation of a high containment pressure to maintain an adequate pump NPSH would result in greater leakage of fission products from the containment and higher potential offsite doses under accident conditions than would otherwise result.*

Additionally, the regulatory position established in this guide is:

> *Emergency core cooling and containment heat removal systems should be designed so that adequate NPSH is provided to system pumps assuming maximum expected temperatures of pumped fluids and no increase in containment pressure from that present prior to postulated loss of coolant accidents.*

This position has essentially remained unchanged in the current guidance, Regulatory Guide 1.82, Revision 3.

Since 1997, we have expressed concerns over the crediting of CAP in NPSH calculations in a series of reports. In a June 17, 1997, report, we stated that CAP should not be granted. In a December 12, 1997, report, we concluded that granting CAP credit of small magnitude may be acceptable in some cases. In our last report on this topic on March 18, 2009, we again stated that hardware changes or requalification of equipment to eliminate the need for CAP should be demonstrated to be impractical, before consideration is given to CAP credit.

The current guidance in Regulatory Guide 1.82, Revision 3, is focused on the conservative calculation of containment pressure for design-basis accidents. The staff contends that the significant conservatism included in the LOCA analyses provides adequate margin. Also, they argue that for special events, which are analyzed with less conservative thermal-hydraulic assumptions, a reasonable level of safety is maintained because of the other conservatisms in the analyses. Although it is true that the licensing-basis analyses currently submitted by licensees to justify CAP credit are based on conservative input assumptions, it is difficult to assess the degree of conservatism and hence the impact on margin against loss of NPSH associated with these analyses.

DISCUSSION

The current guidance in Regulatory Guide 1.82, Revision 3, includes a staff regulatory position that ECCS and containment heat removal systems be designed so that adequate available NPSH is provided to the system pumps, assuming the maximum expected temperature of the pumped fluid and no increase in containment pressure from that present prior to the postulated LOCAs. However, Regulatory Guide 1.82 permits exceptions to this position for operating reactors for which the design cannot be altered in a practical way to achieve conformance with this regulatory position. It appears that the impracticality of such alterations has been essentially presumed in applications for CAP credit. The draft CAP credit guidance now includes an explicit expectation that licensees demonstrate that it is impractical to avoid use of CAP in determining the available NPSH of ECCS and containment heat removal pumps. We strongly support this position. This demonstration should be performed on a plant-specific basis. The staff does not have detailed knowledge of each plant nor are the risks associated with CAP credit sufficiently well characterized for generic waivers to be granted.

If hardware changes are not practical, then analyses to justify the use of CAP credit should be provided. Two types of analyses and justification are needed. First are deterministic licensing-basis analyses, such as design-basis LOCAs, Appendix R fires, Anticipated Transient Without Scram, and station blackout analyses. These are basically the currently required analyses. They are based on the usual licensing-basis assumptions, e.g., for LOCAs, a large break, conservative boundary and thermal-hydraulic inputs, and the most limiting single failure. They are intended to provide conservative estimates of available NPSH under the assumption that containment integrity is maintained. The second type of analyses addresses non-design-basis conditions, i.e., scenarios including failure of containment integrity prior to core damage. Typically these would be based on PRA and would seek to show that the risk associated with CAP credit is acceptably small.

At the present time, requests for CAP credit are associated with licensee requests for power uprates. These license amendment requests are not risk-informed, and, therefore, are not generally supported by a risk analysis. The staff is constrained from seeking risk information for non-risk-informed applications by the policy expressed in Standard Review Plan Section 19.2, Appendix D, and can do so only if “Special Circumstances” are suspected to exist, i.e., if the licensing request creates conditions or situations that would raise questions about whether there is adequate protection and that could rebut the normal presumption of adequate protection from compliance with existing requirements.

We concluded that the long history of questions concerning defense in depth and independence of barriers associated with CAP credit qualify as a sufficient “Special Circumstance” so that licensees can be requested to provide additional analyses or provide additional justification to demonstrate that the risks are acceptably small.

The draft guidance from the staff provides an improved framework for the licensing-basis analyses. In previous reports on the CAP credit issue, we recognized that the deliberate conservatism in the deterministic calculations could make it difficult to assess the actual available margins and the true impact on defense in depth. We recommended that more realistic assessments be performed. Such assessments must consider both the aleatory variability in such parameters as the service water temperature, which can vary significantly through the course of the year, and the epistemic uncertainty in many of the thermal-hydraulic parameters used in the analyses. For this reason, such calculations could be done using a Monte Carlo approach, such as that proposed by the BWROG. It is difficult to define a single representative accident sequence, as suggested in the staff guidance. While the approach suggested by the BWROG is adequate to give an understanding of the range of responses that could occur in an accident and for assessing the potential for damage to the pumps, we agree with the staff and the BWROG that the licensing decision should be based on a conservative, deterministic calculation. Licensees should submit upper bound and mean estimates as well as the 95/95 estimate to provide a more complete assessment of the available margins and impact on defense in depth.

The staff has also reassessed the potential problems associated with operation of pumps near the required NPSH. They have engaged two pump experts and have developed some preliminary criteria to ensure adequate performance of pumps. In addition, for cases in which the available NPSH is less than the required NPSH, even if all the calculated containment accident pressure is credited, they have developed additional guidance to ensure meaningful testing of pumps for operation with NPSH less than the required NPSH. They have also asked that the uncertainty in the required NPSH be addressed in the comparison of available NPSH with required NPSH. The staff recognizes that their current draft guidance in this area is based on relatively limited input and intends to seek further input from industry and pump vendors.

One of the interesting results from this reassessment of pump performance is that the maximum wear rate does not occur at the minimum required NPSH, but rather at a value near 1.4 times the minimum value. The draft guidance addresses this by suggesting that the maximum time of operation with NPSH between 1.1 and 1.6 times the required NPSH be limited. The staff and their consultants believe that 100 hours is a conservative estimate for this limited time of operation, but they are seeking input on additional data and experience to support a higher value. We support the staff's approach and will be interested to see if sufficient data are available to justify the duration of operation.

We disagree with the staff's proposal to use a single "realistic" NPSH time history to determine the period of time the pumps may operate in the region of high wear rate. No single time history can be considered as representative. Instead, the time of operation in the high wear region should be based on the time, during which the range of statistical results intersects the range of NPSH margin ratios, representing the region of high wear rate.

Neither Regulatory Guide 1.82, Revision 3, nor the draft CAP credit guidance explicitly address operator actions, although requests for CAP credit often include the use of operator action. The staff has stated that these operator actions will be reviewed in a manner that is typical of operator actions for design-basis analyses, where the focus is on the feasibility of the action. The staff's review of the operator actions and the associated procedures should include human performance and PRA experts to help assure that the likelihood of undesirable unintended consequences is acceptably small.

To complement the deterministic licensing-basis analyses, which assume containment integrity, realistic analyses that assess the impact of the loss of containment integrity are also needed. These analyses will typically be PRAs. However, if no CAP credit is needed for the special events licensing-basis analyses, and the 95/95 lower tolerance bound for LOCAs calculated using an acceptable methodology shows that no CAP credit is needed, then the CAP credit can be deemed to be small enough that it is acceptable without the need for hardware modifications or additional risk studies. This is consistent with the intent of our previous position that if the CAP associated with the licensing basis analysis is sufficiently "short" and "small," then it can be assumed to be largely due to conservatism in the calculation and does not represent a significant challenge to the independence of barriers and the associated risk is small.

In support of their effort to develop updated guidance, the staff has carried out their own independent risk evaluation of the use of CAP to prevent ECCS pump cavitation. The analysis was performed for an hypothetical BWR with a Mark I containment. In the model, the increase in risk with CAP credit is associated with the occurrence of containment leakage large enough to diminish the pressure in the containment to below that needed for operation of the pumps.

One of the risk insights developed from this study is that the risk is a strong function of the surveillance interval for containment leakage, because it is directly related to the probability of the presence of a pre-initiator containment leak large enough to cause failure of the ECCS pumps. For leakage test intervals believed to be representative of BWRs with Mark I containments (about once per week), the predicted change in core damage frequency, ΔCDF, is less than $1x10^{-7}$/yr, which is very small.

The model assumes that the failure rate of containment isolation after an accident is the same as that during normal operation, despite the more challenging conditions. The containment tests performed by the NRC over the past two decades do show that the containment and seals have robust margins for beyond design-basis conditions under static, isothermal pressure tests. Based on the results presented by the staff, it would appear that a factor of 100 increase in this failure rate is required to increase the ΔCDF by about $1x10^{-6}$/yr. A very large increase in the failure rate does not seem likely, based on environmental qualification programs for design-basis conditions and the NRC sponsored testing that extended into severe accident conditions. However, the model also does not include the possibility that head loss due to sump strainer and other debris blockage is greater than the predicted value used in the calculation of available NPSH. Risk is very sensitive to head loss. The staff's PRA can be used to show that a probability of only $5x10^{-4}$ that debris blockage head loss was underestimated, would increase the ΔCDF to greater than $1x10^{-6}$/yr.

The staff's initial risk assessment was limited to internal events, with no consideration of fire or seismic events. The staff has recently updated their risk study to include some initial estimates of seismic risk. Fire and seismic events introduce modes for loss of containment integrity that are not addressed by the available testing and probably dominate the risk for the class of reactors of most interest, BWRs with Mark I containments. The staff requires consideration of spurious actuations in the Appendix R scenario, but it is not clear what fraction of the fire risk is addressed by this calculation. Clearly, we will have a much better understanding of this risk in plants that have converted to NFPA 805, but until this is complete, any estimate of fire risk is highly uncertain.

The seismic studies provide useful order-of-magnitude estimates and provide assurance the CAP credit does not threaten adequate protection, but better estimates are needed for comparison with Regulatory Guide 1.174 guidelines. Seismic events, fires, and operator actions are potentially significant risk contributors. It is not possible to adequately assess these risks except on a plant-specific basis. Licensees requesting CAP credit should provide these plant-specific risk estimates.

We look forward to further discussions with the staff on these important matters.

Sincerely,

/RA/

Said Abdel-Khalik
Chairman

Additional Comments by Members Dr. Sam Armijo, Dr. Sanjoy Banerjee, Mr. Charles Brown Jr., and Mr. Harold Ray

We agree with the Committee letter, except for Recommendation 5 and the associated discussion on granting of CAP credit. Recommendation 5 states:

"If no CAP credit is needed for the special events licensing-basis analyses, and the 95/95 lower tolerance bound for LOCAs calculated using an acceptable methodology shows that no CAP credit is needed, then the CAP credit can be deemed small enough that it is acceptable without the need for hardware modifications or additional risk studies."

To assure adequate core cooling and containment integrity, the margins implicit in the independence of barriers should be maintained whenever practical by making plant modifications to eliminate the need for CAP credit. Using Recommendation 5 as guidance, licensees requesting plant license amendments that increase licensed thermal power would not have to demonstrate that safety system modifications are impractical, or complete detailed PRAs to quantify the risk of unmodified safety systems. In our opinion, the granting of CAP credit for amendments that increase licensed thermal power should require the following analyses to demonstrate that adequate margins are being maintained for all credible accident and special event scenarios. These include:

1. A thorough evaluation of potential safety system modifications, and implementation of practical modifications that eliminate the need for CAP credit. The criteria used in assessing practicality should be explicitly identified and justified and should be commensurate with the magnitude of the increased thermal power.

2. A plant-specific, full-scope PRA that demonstrates that the increase in risk is small in the event that plant modifications are determined to be impractical.

References:

1. Memorandum to Edwin Hackett, Staff Requirements - Meeting with Advisory Committee on Reactor Safeguards (ACRS), 2:00 p.m., Friday, November 7, 2008, Commissioners' Conference Room, One White Flint North, Rockville, Maryland (Open to Public Attendance) SRM M081107, 01/08/2009 (ML090090338)
2. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.82, Revision 3, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident," January 2003 (ML023100171)
3. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.174, Revision 1, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," November 2002 (ML023240437)
4. U.S. Nuclear Regulatory Commission, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition," Section 6.2.2, Containment Heat Removal Systems, Revision 5, March 2007 (ML070160661)
5. Letter from R. L. Seale, ACRS Chairman, to L. Joseph Callan, NRC Executive Director for Operations, Subject: Proposed Final Generic Letter, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," 06/17/1997
6. Letter from R. L. Seale, ACRS Chairman, to S. A. Jackson, NRC Chairman, Subject: "Credit for Containment Overpressure to Provide Assurances of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," 12/12/1997 (ML091130712)
7. Letter from Joseph Callan, NRC Executive Director for Operations, to R. L. Seale, ACRS Chairman, Subject: Proposed Final Generic Letter, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," 08/15/1997
8. Letter to Luis A. Reyes, Proposed Revision 4 to Regulatory Guide 1.82, "Water Sources for Long-Term Recirculation Cooling Following A Loss-of-Coolant Accident," 09/20/2005 (ML052630562)
9. Letter to Nils J. Diaz, Vermont Yankee Extended Power Uprate, 01/04/2006 (ML060090125)
10. Letter to Dale Klein, Browns Ferry Nuclear Plant, Unit 1, 5-Percent Power Uprate, 02/16/2007 (ML070470314)
11. U.S. Nuclear Regulatory Commission, Safety Guide 1.1 (Regulatory Guide 1.10), "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps," 11/02/1970 (ML003739925)
12. NUREG/CR-6906, "Containment Integrity Research at Sandia National Laboratories, An Overview", 07/31/2006 (ML062440075)

13. Parks, M. B. and Clauss, D. B., "Performance of Containment Penetrations under Severe Accident Loading," Nuclear Engineering and Design, No. 134, 1992, pp. 177-197

14. GE Hitachi Nuclear Energy, Licensing Topical Report, NEDC-33347P, "Containment Overpressure Credit for Net Positive Suction Head (NPSH)," January 2008 (ML080520263) GEH Proprietary Information

pumps. For leakage test intervals believed to be representative of BWRs with Mark I containments (about once per week), the predicted change in core damage frequency, ΔCDF, is less than $1x10^{-7}$/yr, which is very small. The model assumes that the failure rate of containment isolation after an accident is the same as that during normal operation, despite the more challenging conditions. The containment tests performed by the NRC over the past two decades do show that the containment and seals have robust margins for beyond design-basis conditions under static, isothermal pressure tests. Based on the results presented by the staff, it would appear that a factor of 100 increase in this failure rate is required to increase the ΔCDF by about $1x10^{-6}$/yr. A very large increase in the failure rate does not seem likely, based on environmental qualification programs for design-basis conditions and the NRC sponsored testing that extended into severe accident conditions. However, the model also does not include the possibility that head loss due to sump strainer and other debris blockage is greater than the predicted value used in the calculation of available
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We look forward to further discussions with the staff on these important matters.

Sincerely,

/RA/

Said Abdel-Khalik
Chairman

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DATE	5/18/10	5/18/10	5/19/10	5/19/10	5/19/10

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June 10, 2010

Said Abdel-Khalik, Chairman
Advisory Committee on Reactor Safeguards
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: DRAFT GUIDANCE ON CREDITING CONTAINMENT ACCIDENT PRESSURE IN MEETING THE NET POSITIVE SUCTION HEAD REQUIRED TO DEMONSTRATE THAT SAFETY SYSTEMS CAN MITIGATE ACCIDENTS AS DESIGNED

Dear Dr. Abdel-Khalik:

Thank you for your May 19, 2010, letter discussing the staff's draft guidance on the use of containment accident pressure in determining the net positive suction head (NPSH) margin of emergency core cooling system and containment heat removal system pumps. As you pointed out in the letter, the staff and the Advisory Committee on Reactor Safeguards (ACRS) have been discussing this issue both generically and with regard to specific licensing actions for over a decade. The staff appreciates these interactions and continues to benefit from the Committee's review of the staff's work.

In the April 23, 2010, meeting with the ACRS Subcommittee on Power Uprates and the May 6, 2010, meeting with the ACRS, the staff specifically presented information to resolve the difference of opinion with the Committee on the use of containment accident pressure, as directed by the Commission's Staff Requirements Memorandum of January 8, 2009, titled, "Staff Requirements – Meeting with Advisory Committee on Reactor Safeguards." Until the issue is fully resolved, the extended power uprate license amendment requests from the Tennessee Valley Authority for Browns Ferry Nuclear Plant Units 1, 2 and 3 and from Excel Energy for the Monticello Nuclear Generating Plant will remain deferred.

We consider our review of the Boiling Water Reactor Owners' Group topical report, our work developing guidance for the use of containment accident pressure in determining NPSH margin, and our risk assessment to be significant milestones in complying with the Commission's direction to resolve differences with the ACRS on this important issue. However, the staff finds that to proceed further in fully accommodating the ACRS recommendations certain policy issues must first be addressed. Issues such as the use of risk in nonrisk-informed license amendment requests and the concept of defense-in-depth in the staff's review of licensing actions will remain unresolved with the ACRS until these policy issues are addressed.

The staff plans to explore various options in dealing with these policy issues and will seek Commission direction for further action.

Sincerely,

/RA Marty Virgilio for/

R. W. Borchardt
Executive Director
for Operations

cc: Chairman Jaczko
Commissioner Svinicki
Commissioner Apostolakis
Commissioner Magwood
Commissioner Ostendorff
SECY

The staff plans to explore various options in dealing with these policy issues and will seek Commission direction for further action.

Sincerely,

/RA Marty Virgilio for/

R. W. Borchardt
Executive Director
for Operations

cc: Chairman Jaczko
Commissioner Svinicki
Commissioner Apostolakis
Commissioner Magwood
Commissioner Ostendorff
SECY

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Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	52
Requestor:	Campbell/Shaw	Information Request No.	54
Date Received:	February 28, 2014		

Question 52:

What was the level of contingency included in the original LCM project budget estimate and what was the basis for the level of contingency assumed?

a. How was the level of contingency modified and by what percentage for each of the four (4) estimates in the ten (10) Subprojects identified in DOC Ex. 171 NAC-30 (Campbell Direct) Docket E002/GR-12-961?

b. If contingencies were not modified or were not included in the budget estimate at any point in time, please provide and explanation for the decision not to include contingencies.

Question 54:

What was the level of contingency included in the original EPU project budget estimate and what was the basis for the level of contingency assumed?

a. How was the level of contingency modified and by what percentage for each of the four (4) estimates in the ten (10) Subprojects identified in DOC Ex. 171 NAC-30 (Campbell Direct) Docket E002/GR-12-961?

b. If contingencies were not modified or were not included in the budget estimate at any point in time, please provide and explanation for the decision not to include contingencies.

Response:[1]

Information Request DOC-52 requests information regarding the use of contingency in the "LCM project." Similarly, Information Request DOC-54 requests the same information for the "EPU project." As the Company did not account separately for the LCM and EPU aspects of the Program, we will respond to these questions together.

First, our response to Information Request DOC-49 provides additional detail on the budget levels that were in place from time to time and the presence or absence of contingency amounts in place under those budget estimates. The following summarizes the use of contingencies.

The initial level of contingency set in the initial Nuclear Projects Authorization ("NPA") was set at $15.431 million plus $7 million in 2006 dollars for two different contingencies. This contingency represented approximately 10% of the initial $273 million (2006 dollars) authorized for the LCM/EPU Program.

This contingency level was modified in late 2011 when the overall estimate was increased to $586.7 million. This estimate was based upon the cost study provided to us by one of our vendors. This is the estimate that was presented to the Commission in our 2012 rate case, Docket No. E002/GR-12/961. This estimate did not include any contingency amount.

In January 2013, the 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.

a. The level of contingency was never allocated among the subprojects but was treated as an aggregate amount. Thus, at the time the initial NPA was authorized and during subsequent budget discussions, the contingency was not allocated among the 10 subprojects identified in the

[1] Note that all documents referred to in this Response will be produced pursuant to and as part of DOC IR-050, which generally seeks documents responsive to all of DOC IR-048 – 064. The Company notes that a number of the documents provided in response to DOC IR-050 contain confidential employee information, Xcel Energy trade secret information, and third-party trade secret information. Documents produced pursuant to DOC IR-050 will be produced with the appropriate designation as part of our response to that information request. The Company chose this method for producing documents to ensure that the responses to the information requests could be disclosed publicly to the maximum extent possible and to avoid any delay that may occur in preparing voluminous confidential documents for production.

question. However, as described in more detail in our answer to Information Request DOC-51, in reconciling the original authorization with the amounts spent, we allocated the costs across the subprojects.

b. Contingencies were modified as described above and in our response to Information Request DOC-53.

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Department:	Nuclear Operations
Telephone:	612-330-6083
Date:	March 13, 2014

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Xcel Energy
Docket No.: E002/CI-13-754
Response To: Department of Commerce Information Request No. 68
Requestor: Nancy Campbell/Chris Shaw
Date Received: March 27, 2014

Question:

In light of the last sentence of the penultimate paragraph of page 6 or IR response 51/53 p.6 (…it is not unusual for actual costs to vary substantially from initial estimates…), why did the Company not include and support contingencies when developing their project estimates for Monticello?

Response:

While the statement referenced above is accurate, the decision whether to utilize contingencies in our Project budgeting, and the amount of those contingencies, depended on the managerial cost control strategy in place at that time.

Historically, the use of contingency in the nuclear organization has been quite limited. The Nuclear business unit historically used a fixed budget number with the view that this would help manage costs. For example, our outage maintenance budgets did not included contingency amounts in them for much of this same period.

The LCM/EPU Project cost estimates did include contingency, although based on the same history, the amounts were quite limited and not adequate for the project. The 2006 Nuclear Project Authorization included two different contingencies in 2006 dollars: $15.431 million (overhead and contingency) and a separate $7.726 million (contingency). As the project moved forward contingency was eliminated once again, with the belief that this was a means of attempting to drive costs to the new updated forecast levels. When it became clear this approach was ineffective, we added an additional $20 million of contingency to the project in 2013 although this contingency was protected from our key implementation vendor so as to continue to incent them to meet the target.

Preparer:	John Bjorseth
Title:	General Manager- Fleet Operations
Department:	Nuclear Operations
Telephone:	612-330-6083
Date:	April 8, 2014

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Xcel Energy
Docket No.: E002/CI-13-754
Response To: Department of Commerce Information Request No. 76
Requestor: Nancy Campbell/Chris Shaw
Date Received: March 27, 2014

Question:

See IR response 64. Please explain the different regulatory environment at Duane Arnold Energy Center (DAEC) than at Monticello.

Response:

There are several important differences between the regulatory environment that existed when Duane Arnold Energy Center (DAEC) received its EPU license amendment in 2001 and the environment that existed when Monticello received its EPU license amendment 12 years later in December 2013. The NRC has stated many times that it is a learning organization, resulting in evolving standards and new requirements as it gains experience with particular issues. This dynamic is also a fundamental tenet for management at nuclear utilities.

The differences in the regulatory environment fall within the following general categories, each of which is described below: (i) regulatory approach to steam dryer performance has evolved considerably from 2001 to 2013; (ii) regulatory approach to containment accident pressure (CAP) underwent a dramatic regulatory change from 2009-13; (iii) the NRC's treatment of the backfit rule and the concept of forward fit has changed considerably since DAEC received its EPU; (iv) the NRC Staff's interpretation of NRC Review Standard RS-001 has undergone significant change in approach; and (v) the NRC review process has generally become more detailed and prescriptive since 2001.

(i) Steam Dryer
In 2001, when DAEC received its EPU license amendment, the NRC was not focused on issues relating to the integrity of the steam dryer. As a result, DAEC did not receive significant scrutiny on this component. The Quad Cities nuclear station

received EPU approval from the NRC shortly after DAEC's EPU was approved. Similar to DAEC, Quad Cities did not replace the steam dryer because the analysis at the time demonstrated that the existing steam dryer provided sufficient margin. However, the added steam from the uprate capacity created too high a velocity for the piping configuration at Quad Cities resulting in the dryer cracking in 2003. The experience at Quad Cities, as well as similar issues at the Dresden nuclear station, caused the NRC to begin investigating making the review requirements for steam dryer performance more rigorous.

When we filed the Monticello EPU LAR in 2008, it was not clear how the steam dryer would be treated. As described in detail in Mr. Timothy O'Connor's Direct Testimony at pp. 52-54, the Company ultimately amended its application to include a replacement steam dryer as part of the evolving regulations. Even after the decision was made to replace the steam dryer, the NRC review required significant analysis on the performance of the proposed new steam dryer to ensure that it would perform within NRC required tolerances. None of these issues were raised with DAEC.

(ii) <u>CAP</u>
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 ECCS pump performance. In prior EPUs the NRC accepted the CAP analysis based on previously approved licensing methods.

As described in Mr. O'Connor's Direct Testimony at pp. 55-57, as well as in the Response to DOC IR No. 75, the NRC staff became concerned about previously approved CAP analysis methods during the Monticello EPU analysis. This became a significant issue for Monticello that resulted in considerable additional analysis, cost and delay. This issue was also not prominent when DAEC was seeking its EPU.

(iii) <u>Back Fit v. Forward Fit</u>
The NRC back fit rule has undergone a significant evolution since DAEC received its EPU amendment. This has resulted in considerable additional analysis for Monticello that was not faced by DAEC.

Under 10 CFR Part 50.109, the NRC generally does not require nuclear operators to "back fit" systems (apply a change in criteria retroactively to an existing licensee) unless the NRC can demonstrate that there is a substantial increase in the overall protection of the public health and safety or the common defense and security to be derived from the back fit and that the direct and indirect costs of implementation for that facility are justified in view of this increased protection. This limitation provides licensees some comfort that they can rely upon the chosen design of their systems and once those designs are approved, the NRC will not seek retroactive changes, except in unusual circumstances.

At the time that DAEC received its EPU in 2001, the back fit rule was generally applied in a way that did not require significant additional work by the applicant in order to comply with the new requirements. However, by the time Monticello pursued its EPU in the 2008-13 time-frame, the back fit rule became a significant issue for consideration. After DAEC received its EPU, the NRC staff began considering the concept of "forward fit" which effectively increases the scope of NRC review of changes proposed to be made as part of a voluntary licensing action such as an EPU.

The NRC's current view is that for a licensee who voluntarily seeks to change its licensing basis, the NRC may condition its approval of the proposed change upon a licensee agreement to adopt new or revised guidance whether or not the condition is predicated on a substantial safety issue (as limited by the back fit rule). Since a voluntary license change is initiated by the licensee to take advantage of a voluntary alternative offered in the NRC's regulations, the NRC's current position is that the agency is not bound by the limitations of the back fit rule.

This view is new since DAEC received its EPU LAR. Since a voluntary license change is initiated by the licensee to take advantage of a voluntary alternative offered in the NRC's regulations, the NRC's current position is that the agency is not bound by the limitations of the back fit rule. Additionally, see the Generally Increased Review section below for examples of the additional work that had to be addressed at Monticello that were different than DAEC's initial EPU work

(iv) RS-001

The NRC has published a set of review standards governing review of license amendment applications for power uprates. These review standards are intended to provide a comprehensive basis for the NRC to review thoroughly such applications. This process creates a highly technical set of requirements that must be met when seeking a license amendment to uprate the capacity of a plant. The result is that licensees can be subject to requirement changes.

At the time that DAEC received its EPU license amendment in 2001, RS-001 was interpreted in a way that it did not require major new requirements. Monticello, by contrast, was required to include significant new analysis to satisfy the requirements under RS-001, which resulted in additional costs to the Monticello LCM/EPU Project.

(v) Generally Increased Review
Fundamentally, the NRC review process has evolved significantly since DAEC received its EPU in 2001.

Nuclear utilities such as Xcel Energy must be learning organizations and be dedicated to self-improvement in order to ensure safe and reliable implementation and to meet the evolving requirements of the NRC. Nowhere is there a culture more dedicated to self-improvement than in the nuclear power industry. The focus on safety and reliability demands that a utility adapt, evolve, and continually strive to get better. Far from a sign of imprudence, it is expected that utility managers review recently completed work efforts and probe how they can perform better in the future. This is also an NRC requirement and is best described as the corrective action program. The self-critical approach utilized in the industry coupled with a credible regulator is the main reason for the high levels of safety and performance in the U.S., among the best in the world.

The NRC principle to view nuclear safety issues from the frame of reference of "defense-in-depth." This underlying principle is always at the heart of nuclear regulation. The defense-in-depth concept becomes more prominent whenever there has been an adverse incident in the nuclear industry as the agency refocuses its attention on the cause of the adverse event and reexamines whether the additional measures need to be implemented in light of the event.

The Great East Japan Earthquake and the ensuing tsunami that devastated the Fukushima nuclear plant in Japan in March 2011 was the most recent such event. The Fukushima situation highlights that accidents caused by extreme natural disasters can overwhelm a plant's safety systems. While it is clear that U.S. nuclear power plants are better prepared for severe events, Fukushima plus other examples have prompted the NRC to substantially shift its focus and intensify its consideration of defense-in-depth concerns around natural disasters and the potential for the loss of on-site power at a nuclear plant.

Further, the NRC's evolving regulations included significant requirements not applicable to DAEC. DAEC took the view that it could replace a number of important secondary systems after the EPU upgrades where Monticello concluded that it was prudent to include those systems in the initial scope of overall work. Safety and NRC compliance considerations required Xcel Energy to undertake significantly more work to upgrade or replace additional systems that had aged or were not able to be utilized through 2030. Examples of the additional work that had to be addressed that were different than DAEC's initial EPU work: (i) replacement of all six feedwater heaters as opposed to undertaking minor rerating of the existing heaters, (ii) replacement of the entire condensate demineralizer system as opposed to only replacing the vessels (tanks), (iii) implementing a two-pump solution to the reactor feed pumps and motors as opposed to adding a third small supplemental pump, and (iv) addition of the 13.8 kV internal distribution system. The scope expansion from these four items caused a substantial amount of the increased cost experienced by Xcel Energy.

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State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CI-13-754 (Commission Investigation into the Monticello LCM/EPU Project)

Date Request Received: July 24, 2014

Date of Response: August 5, 2014

Person Requesting Information: Timothy J. O'Connor

Response submitted by: Mark W. Crisp

Request No.	
7	Re: Direct Testimony and Attachments of Mark W. Crisp Reference Crisp p. 16, lines 15-16. Please describe which specific project designs were "fully functional 'on paper'" that could not be "physically built." DOC Response: My discussion of "fully functional 'on paper'" and …. "the design cannot be physically built" is a general reference to the subject of that particular paragraph, i.e., "It is essential in a well-managed and executed Project Management Plan that the initial design and the construction functions have a solid connection between the two functions." I did not reference any specific project designs.

Project	In Service Date	Tech.	Initial Cost Estimate	Actual Cost	Initial to Final Cost	Estimate of Schedule Extension	Principal Causes of Cost and Schedule Changes
Callaway 1	Dec 1984	PWR	$1.088 billion	$2.850 billion	$1.762 billion	2.75 years	• Regulatory delays: NRC construction permit, design certification • Commodity cost increases • Engineering costs from design evolution
Limerick 1 & 2	Unit 1: Feb 1986 Unit 2: Jan 1990	BWR	$716 million	$6.9 billion	$6.184 billion	Unit 1: 10-11 years Unit 2: 14 years	• Regulatory delays: environmental permits, construction permits (partially related to TMI) • Construction and commodity cost escalation • Declining load growth
Seabrook	Aug 1990	PWR	$1 billion	$6 - $6.5 billion	$5 - $5.5 billion	11 years	• Regulatory delays: environmental permitting
Susquehanna 1 & 2	Unit 1: Jun 1983 Unit 2: Feb 1985	BWR	$1.185 billion	$4.1 billion	$2.915 billion	4 years	• Engineering costs from design evolution
Vogtle 1 & 2	Unit 1: May 1987 Unit 2: May 1989	PWR	$600 million	$8.87 billion	$8.27 billion	Construction began in 1976, approximately 11 & 13 years before the two units reached commercial operation.	• Engineering costs from design evolution (post-TMI) • Construction and commodity cost escalation
Vogtle 3 & 4	Unit 3: Late 2017 Unit 4: Late 2018 (expected)	PWR	$6.113 billion (for Georgia Power's 45.7% ownership interest)	$6.759 billion	$381 million	Approximately one year from CODs when the project was approved.	• Changes in federal regulations • Transmission costs • Construction and commodity cost escalation
Wolf Creek	Sep 1985	PWR	$525 million	$3 billion	$2.475 billion.	4.5 years	• Engineering costs from design evolution (post-TMI) • Construction and commodity cost escalation

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Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	51
Requestor:	Campbell/Shaw	Information Request No.	53
Date Received:	February 28, 2014		

Question 51:

Please provide the original budget estimate for the LCM project and provide the basis for this estimate including any spreadsheets, contractor or equipment supplier budgetary estimates, or other estimating documents.

Question 53:

Please provide the original budget estimate for the EPU project and provide the basis for this estimate including any spreadsheets, contractor or equipment supplier budgetary estimates, or other estimating documents.

Response:[1]

Questions 51 and 53 ask for how the original budget estimate was developed for the LCM and EPU aspects of the LCM/EPU Program. This response provides information responsive to both of these questions by describing the project development of both the LCM and EPU aspects, the initial estimate, how the final costs were incurred, and a detailed explanation of the variance between the original overall budget and the final cost of each of the major subprojects. Documents

[1] Note that all documents referred to in this Response will be produced pursuant to and as part of DOC IR-050, which generally seeks documents responsive to all of DOC IR-048 – 064. The Company notes that a number of the documents provided in response to DOC IR-050 contain confidential employee information, Xcel Energy trade secret information, and third-party trade secret information. Documents produced pursuant to DOC IR-050 will be produced with the appropriate designation as part of our response to that information request. The Company chose this method for producing documents to ensure that the responses to the information requests could be disclosed publicly to the maximum extent possible and to avoid any delay that may occur in preparing voluminous confidential documents for production.

responsive to this question are provided in response to DOC IR 50. Specific references to specific responsive documents will be provided within the response.

Introductory Information

Subproject Identification and Description

These questions request that budget and cost information be provided for each "subproject with an original capital budget in excess of $500,000." Schedule 8 to the Direct Testimony of Mr. O'Connor provides a listing of all subprojects (also referred to as 'Child Work Orders') for the overall Program. As reflected on that Schedule, there were 49 subprojects comprising the Program. The substantial majority of those subprojects exceeded the $500,000 threshold in the question. In addition, as described in our filing, we grouped subprojects into overall projects we refer to as the "Major Modifications". There were 10 major modifications (including licensing), each of which substantially exceeded the $500,000 threshold. In describing the budgeting and cost information in this response we have maintained the same structure as found in our filing of describing the 10 major modifications as the primary cost drivers for the Program.

LCM/EPU Aspects of the Program

Questions 51 and 53 separately ask for discussion of the original budget estimate for the LCM and EPU aspects of the overall Program. Likewise, Questions 55 and 56, seek further information separately for LCM and EPU expenditures for the major subprojects. As described in more detail in our filing, the Company did not separately develop or track discrete LCM-only or EPU-only costs

Rather, the Company 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 2030. In the 2003-07 timeframe (when Xcel Energy was seeking Monticello's license extension as well as developing the parameters of the LCM/EPU Program), the Company recognized that capital investments were needed to ensure the long-term safe and reliable operation of the plant to support the license extension. Some of these replacements were required in the short term, while others were identified for completion later in the license renewal period. Further, some upgrades were needed, in part, to support operations at uprate levels and still other upgrades served multiple purposes. This issue is described in Exhibits 29 and 30 of Mr. O'Connor's Direct Testimony which provides a discussion of the types of costs incurred and the Company's separation of those costs into LCM or EPU (or combination) activities.

In any case, as the Program was being implemented, the Company did not budget or track costs separately for the LCM or EPU components. Rather, to maximize the overall value of the plant for our customers, we decided it was important to implement all upgrades necessary to replace worn equipment as well as those upgrades that we assessed would reasonably need to be replaced in the next few years to support operations through the end of our extended license in 2030. As a result, our response to these questions regarding estimates will combine the LCM and EPU aspects together.

Documents

We note that the discussion of the creation of the initial estimate provided by the Company in our filing and in this response provides analysis and compilation of budget information developed over time. As described in our filing, the Program evolved over time as the Company adapted to changing circumstances. As a result, the underlying documents provided in many instances do not precisely tie to the initial budget described in the filing. The initial $320 million cost estimate that was provided to the Department in response to DOC IR-160 in our last rate case, Docket No. E-002/GR-12-061 (and was updated in Schedule 8 of Mr. O'Connor's Direct Testimony), was derived as described in the filing and in this answer. Additional documents that support the original budget and are responsive to these requests are provided with our document production including, the July 11, 2006 EPU Feasibility Cost Spreadsheet, the long range plans, the 2007 Nuclear Project Authorization, the 2006 GE Contract, and the GE cost scoping and feasibility studies.

Original Budget Estimate (LCM and EPU) – Questions 51 and 53

In 2004, the Nuclear Management Company ("NMC") retained General Electric Company ("GE") to study the potential of uprating Monticello to 120% of its original licensed thermal power. In July 2004, GE issued its "Extended Power Uprate/MELLLA+ Feasibility Study" ("GE Feasibility Study") for Monticello. The study concluded that an uprate of 120% would maximize the benefits from the project, and that such an uprate was technically feasible at Monticello. The initial estimated cost in 2004 was $86 million for EPU mods (2004$), but it did not include equipment replacements such as the feedwater heaters, LCM related modifications, or NMC's and Xcel's internal costs.

Next, NMC produced its "Monticello Nuclear Generating Plant, Feasibility and Cost Study for the Extended Power Uprate Project," in September 2004 ("NMC Feasibility Study"). The NMC Feasibility Study included the following scope of work:

- HP and LP turbine modifications
- Feedwater heaters re-certification or replacement
- Feedwater and condensate pumps/motors modification or replacement
- Implementation of MELLLA+ Operating Domain
- DSS-AB Long Term Stability Solution change from Option 1-D
- 1R transformer modification or replacement.

The NMC Feasibility study developed a high ($91.5 million) and low estimate ($60 million) of the cost to complete the identified scope. The low estimate was premised on successful negotiations to reduce GE's fees to complete the work and reducing or avoiding scope such as:

- Recertifying the existing feedwater heaters rather than undertaking replacement
- Elimination of management reserves and contingencies
- Reducing the GE performance fee by 50%
- No jet pump cleanings
- Minor steam dryer modifications
- No major pump/motor modifications or replacements
- Modifying rather than replacing the 1R transformer.

The high estimate included a risk allowance for the steam dryer modifications and possible replacement, a management reserve for extended NRC licensing activities similar to those experienced by the Vermont Yankee plant, and overall contingency of 10%. The overall contingency was selected assuming the project was of moderate risk. The overall contingency was not applied to the management reserve.

The NMC Feasibility Study concluded by suggesting that the EPU project should be initiated in 2006. In the meantime, it was suggested that NMC undertake a number of front-end loading activities to further study and prepare for the implementation of the project. Ultimately, NMC and Monticello elected to defer the EPU Project due to competing plant projects.

The GE "Extended Power Uprate Cost Scoping Assessment" (GENE-0000-0050-8232) was prepared in May 2006 ("Initial Scoping Assessment") and provided a budgetary estimate for a 120% OLTP EPU implementation of $98 million (with a target accuracy of +/- 20%) excluding optional scope items that were later incorporated into an engineering and procurement agreement with GE. With the optional scope that was selected by NMC, the EPU cost estimate totaled $123.2 million.

The Initial Scoping Assessment did not include, among others, NMC project management cost, NMC Engineering review costs, incremental outage costs, simulator modification costs, or comprehensive station procedure revisions or replacement power costs. Rather, the budgetary estimate was generic to the EPU product without evaluation of the Monticello Nuclear Generating plant specific requirements, plant or system configuration, aging conditions at the facility, or installation requirements. As described below, additional funds were budgeted to cover these costs and were included in the initial NPA that received Board approval in August 2006 for $274 million, in 2006 dollars.

The Initial Scoping Assessment included a $3.1 million allowance for steam dryer modifications that were not included in the GE Feasibility Study. Likewise, the election to include three optional scopes of work (i.e., a new exciter, a new main transformer, and a generator field rewind) increased the costs as estimated in 2004. In all three cases, the decisions to include the optional scopes of work were based on lifecycle management considerations because the three components were nearing the end of their expected useful lives or were projected to exceed their original design specifications.

The final driver of the increased costs is related to balance of plant modifications. These modifications include new condensate demineralizers ($6.8 million), new feedwater heater drain control valves ($1.8 million), main stream and main stream drain tank level control ($1.6 million), aux power conversion ($3.5) and IsoPhase Bus replacement ($2.7 million). These items were added to the scope or the scope of the modifications was increased to reflect further investigation and analysis by GE during the 2006 Initial Scoping Assessment.

The original estimate as described throughout the filing, and included as the initial estimate identified in DOC Ex. 171, NAC-30 (Campbell Direct) Docket E002/GR-12-961, was a 2008 estimate of $320 million that was used for modeling alternatives in the 2008 Certificate of Need proceeding, Docket E-002/CN-08-185. This estimate was developed from the initial scope of work put together in 2006 with the aid of General Electric. This amount was derived as follows:

Summary of Monticello LCM/EPU Program
Original Cost Estimate (In Millions)

Original Cost Estimate Description	Original Cost Estimate
GE Design, Engineering and Procurement Costs	$ 125.1
Non-GE Costs	148.9
Subtotal	$ 274.0
Steam Dryer Allowance	29.0
Escalation For GE-Related Costs [2]	7.8
Escalation For Non-GE Costs	9.2
Total	$ 320.0

Mr. O'Connor's testimony segregates this $320 million overall estimate among the major modifications and allocates the common costs among the modifications. Schedule 8 of Mr. O'Connor's Direct Testimony provides additional discussion of how this estimate was prepared and what it includes. This estimate is a refinement of the Company's response to DOC IR 160 as used in DOC Ex. 171, NAC-30 (Campbell Direct) in our last rate case, Docket No. E-002/GR-12-061.

At the time this estimate was prepared, the Company had not completed detailed scoping review nor any detailed design engineering to support a final cost estimate and the Company had to rely upon good faith estimates of information known at the time. High level modifications to scope occurred through 2007 and 2008 and were believed to be able to be accommodated in the original NPA with two exceptions. A separate authorization was needed for the Steam Dryer and the transition from a 4 kV solution to a 13.8 kV solution to the electric distribution system. Detailed engineering was completed through an iterative process as the modifications were developed and implemented throughout the six-plus year schedule. It is both common and necessary to implement projects of this type through such an iterative process and as a result it is not unusual for actual costs to vary substantially from initial estimates as the engineering is completed and the magnitude of the task becomes clearer.

As noted, the $320 million estimate was a high-level and good-faith estimate of the overall cost to complete the initiative. As a result, that estimate was not specifically segregated among the major modifications in any detailed way.

[2] Xcel Energy's total original cost estimate included $17 million in escalation costs. For purposes of this proceeding, we allocated $7.8 million of the $17 million escalation cost to the GE-related costs and $9.2 million of the $17 million escalation cost to the Non-GE costs.

At the outset of the Program, Xcel Energy established a single general Work Order (10435578) for the Monticello LCM/EPU Program to track Program costs. This was because the Company viewed the overall initiative to be a single project at that time. As the LCM/EPU Program matured, it became necessary to segregate costs among subprojects for regulatory and accounting purposes so that we could properly account for subprojects that had actually gone into service. Subproject work orders were then created for the various modifications that were being implemented as part of the Monticello LCM/EPU Program. In general, costs that could be directly assigned or attributed to certain modifications were transferred from the general Work Order to the specific Work Order for that modification. Next, the general costs in Work Order No. 10435578 were allocated proportionally to subprojects based on the total amount recorded directly to those Work Orders. The Direct Testimony of Company Witness Weatherby discusses this in more detail. After identifying certain original cost estimate amounts that were easily segregated into one of the six major projects, Licensing or "Other," we allocated the common cost portion of the original cost estimate consistent with Xcel Energy's actual approach for allocating general costs to Work Orders. In preparing Mr. O'Connor's testimony and updating the Company's response to DOC IR No. 160, we developed an allocation of the costs among the largest modifications. Finally, we applied an escalation factor to bring the estimate up from 2006 dollars.

The current allocation among the major subprojects as described in the Company's response to DOC IR 160 (and shown in Ms. Campbell's rate case testimony) is shown below:

Original Cost Estimate For Each Modification
(In Millions)

Modification	**Cost Estimate Amount**
13.8 kV Distribution System[3]	$ 20.9
Condensate Demineralizer	18.0
Feedwater Heaters	37.0
Reactor Feed Pumps/Motors	27.8
Steam Dryer	35.9
Turbine Replacement	60.2
All Other Work Orders	91.6
Licensing	28.6
Total	$320.0

[3] The 13.8 kV project was not part of the original budget but upgrades to the 4 kV system were and this is what this cost represents as the project evolved from 4 kV to 13.8 kV. Similar changes to scope existed for several of the other major subprojects.

We note that in response to Information DOC-37, we provide additional discussion of the development of this initial estimate and explain why the estimate contained in Schedule 8 of Mr. O'Connor's Direct Testimony differs from our initial response to Information Request DOC-160 in Docket No. E002/GR-12-961.

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Xcel Energy
Docket No.: E002/CI-13-754
Response To: Department of Commerce Information Request No. 037
Requestor: Nancy Campbell, Chris Shaw & Steve Rakow
Date Received: December 10, 2013

Question:

Please reconcile differences in the four Major Scope additions in the 2008 Estimate when comparing Table of O'Connor Direct and Schedule 5 of Weatherby Direct, and then tie back to certificate of need estimate, as follows:

	O'Connor Direct 2008 Estimate Per Table 1	Weatherby Direct January 2008 Est. Per Schedule 5
13.8 kV System Addition	$20.9 million	$0 – not in scope
Condensate Demineralizer System Replacement	$18.0 million	$9 million
Feedwater Heater Replacement	$37.0 million	$2.9 million
Reactor Feed Pump Replacement	$27.8 million	$9.8 million
Total	$103.7 million	$21.7 million

Response:

The 2008 estimate included in Schedule 5 of the Direct Testimony of Scott Weatherby comes from the Company's response to DOC IR 160 in our most recent rate case, Docket E-002/GR-12-961. The 2008 estimate in Table 1 of my Direct Testimony (on page 5) comes from the Company's supplemental response to DOC IR 160, which is attached as Schedule 8 to my testimony.

The Company's Supplemental Response and the update of the cost estimates is explained in detail in Schedule 8 of my testimony. We had committed to provide an update of DOC IR 160 as part of this filing.

The Company's initial answer to DOC IR 160 was provided during discovery in the rate case and was based on the best information available to the personnel who were charged with answering that question. That response was prepared at the direction of the Company's accounting function because at that time, the Company's nuclear personnel were fully engaged in preparing for the spring 2013 implementation outage. The personnel who prepared that answer used the information that was available to provide a good faith response to the question. In addition, our initial overall estimate of $320 million was viewed more as a high-level aggregate number and in some instances was not broken down into subproject estimates. Finally, that estimate included a significant amount of non-segregated common costs which could not reasonably be assigned or allocated completely since not all of the subprojects were completed.

In hindsight, the answer to IR 160 in the rate case was not as clear as it could be and did not completely describe the items that were included in the initial $320 estimate used for modeling purposes in the Certificate of Need proceeding. For example, in that original answer we stated that the 13.8 kV system was not within the scope of the initial estimates. The reason for this is that the cost estimates that were reviewed in preparation of that original response did not identify the 13.8 kV system by name but rather referred to the need for bus work and upgrades of the internal electrical distribution system. It was not recognized that the electrical system upgrade work was of the same category as what ultimately became the 13.8 kV system. Other examples are that the initial response to IR 160 did not account for or allocate common costs and did not fully account for implementation costs. The cost estimates in Schedule 5 of Company witness Mr. Scott Weatherby's Direct Testimony did not include common or installation costs in the estimates. Table 1 of my testimony (and correspondingly Table 2 of Schedule 8) does include allocations for common and installation.

The table below reconciles the estimates shown in Table 1 and Schedule 5.

Modification	Table 1	Schedule 5	Explanation of Difference
13.8 kV	$20.9 million	$0 – not in scope	Table 1 includes originally planned electrical distribution upgrades ($11.6 million) and an allocation of common costs ($9.3 million).
Condensate Demineralizer System Replacement	$18.0 million	$9 million	Table 1 reflects a refined breakdown of the initial project cost estimate as well as an allocation of installation ($1.6 million) and common costs ($13.5 million).
Feedwater Heater Replacement	$37.0 million	$2.9 million	Table 1 includes additional child work orders under this major modification (included as "other subprojects" in Schedule 5) and reflects an allocation of installation ($6.0 million) and common costs ($22 million).
Reactor Feed Pump Replacement	$27.8 million	$9.8 million	Table 1 reflects allocated installation ($9.1 million) and common costs ($6.3 million).
Total	$103.7 million	$27 million	Table 1 includes $16.7 million and $50 million in installation costs and common costs, respectively, which were not allocated to major modifications in Schedule 5.

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Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	106
Requestor:	Chris Shaw, Nancy Campbell		
Date Received:	April 25, 2014		

<u>Question:</u>

Please list how many of these outages involved major projects in containment and in the turbine generator building, along with the dates of such outages.

<u>Response</u>:

As stated in our response to DOC Information Request No. 105, there have been 19 refueling outages (RF) since 1981. All of those outages have involved projects in containment and in the turbine generator building.

For the purposes of this response, we define a project as separately funded and authorized discrete work-scope for activities that are not performed at a pre-established interval or on a routine basis. A project has defined start and end points, defined objectives for completion, and measurable results directed at closing gaps in performance.

Projects include those temporary endeavors that are generally estimated to cost greater than $500,000 excluding material costs and overheads. Projects are neither routine nor base level work, but can be funded with either O&M or capital dollars. Projects can be modifications or physical facility changes or maintenance activities on major components or risk significant components. Further, any effort that is deemed sufficiently complex such that it would benefit additional project controls can be classified as a project and have a project manager assigned.

The refueling outages since 1981 occurred on the following dates:

- **RF-8**: 4/20/81- 5/12/81

- **RF-9**: 9/1/82-12/9/82
- **RF-10**: 2/3/84-1/19/85
- **RF-11**: 4/30/86-7/13/86
- **RF-12**: 10/22/87-12/19/87
- **RF-13**: 8/18/89-11/5/89
- **RF-14**: 3/31/91-5/31/93
- **RF-15**: 1/27/93-3/25/93
- **RF-16**: 9/15/94-10/23/94
- **RF-17**: 4/10/96-5/23/96
- **RF-18**: 3/20/98-4/25/98
- **RF-19**: 1/6/00-2/29/00
- **RF-20**: 11/3/01-12/15/01
- **RF-21**: 4/26/03-5/26/03
- **RF-22**: 3/5/05-4/12/05
- **RF-23**: 3/14/07-4/28/07
- **RF-24**: 3/14/09-5/8/09
- **RF-25**: 3/5/11-5/25/11
- **RF-26**: 3/2/13-7/19/13

While all of the outages involved major projects in containment and in the turbine generator building, records related to outages before 2000 (RF outage 19) are not maintained electronically and will require a substantial effort to search for the information request. The Company will work with the DOC to providing information not included in this response.

RF-19 (1/6/00-2/29/00): **Outage Duration was 54.7 days**

1) Completed 1143 work orders consisting of corrective and preventative maintenance.
    - Major maintenance activities beyond modifications, included replacing cells on #12 125volt DC & # 16 250-volt DC station battery, and alterations of all four in-board MSIVs.
    - Repaired CV-6-12A & CV-6-12B Main Feed Regulating valves.
    - Cleaned the TORUS using divers.
    - Reactor vessel activities consisted of In Vessel Visual Inspection (IVVI), in vessel UT weld inspections, normal fuel shuffle/reload.

<u>RF-20 (</u><u>11/3/01-12/15/01):</u> **Outage Duration was 42 days**

1. Completed 1343 work orders consisting of corrective and preventative maintenance.
    - Major maintenance activities beyond modifications included a ten-year inspection/overhaul of a circulating water pump, replacement of #13 250-volt DC station battery, and alterations of all four outboard MSIVs.
    - Reactor vessel activities consisted of In Vessel Visual Inspection (IVVI), in vessel UT weld inspections, normal fuel shuffle/reload, the replacement of four control blades and rectification of a stuck control rod caused by foreign material.

2) Completed of 39 modifications.
    - The Off Gas modification was the most significant modification implemented during RFO-20. The purpose of this upgrade was to simplify operation, reduce causes of automatic trips and eliminate hydrogen burns in the Off Gas system. Hydrogen burns have been the cause of several forced outages at MNGP. This modification consisted of replacement of the old Off Gas system with a new full steam dilution design. Both Steam Jet Air Ejector skids and associated piping were replaced involving ≈ 1000 welds.

The 2001 refueling outage was originally scheduled to begin on Oct. 3, 2001 however the actual start date was delayed until Nov. 3, 2001 due to a 39 day forced outage to address Section XI issues which occurred in February. Based on the events of September 11, 2001 the station entered a heightened level of security and severely limited the work allowed in the plant for the three weeks just prior to the outage. This impacted the pre-outage work and caused some work that would have been done online to be included in the outage scope.

<u>RF-21</u> <u>(4/26/03-5/26/03):</u> **Outage Duration was 30 days**

1) Completed 1396 work orders consisting in part of 240 Corrective, 730 Preventative, 254 Elective and 172 other maintenance work orders.
2) Completed of 553 scheduled surveillances.
3) Completed of 20 modifications. The most significant were:
    - Emergency Diesel Generator (EDG) Exhaust line support modification for #11 & # 12 EGD's. Addition of pipe supports and support modifications to return EDG exhaust piping to meet code allowables for tornado wind loading.
    - The Turbine Generator Exciter/Turbine Building Vibration modification was another significant modification implemented during RFO-21. New

shim packs were added, doweling checked, coupling changed, bearings re-drilled to make elliptical, end-shields were straightened and stiffener lugs were added at the corners of the Exciter. In addition a balance shot was performed on the machine during start-up.

- Installation of Permanent Drywell Shielding. The scope of this project for the 2003 outage was installation of shielding on portions of the 12 inch and 28 inch reactor recirculation system vertical risers as identified by radiation protection. As-built information on interferences associated with the horizontal header was completed during the 2003 outage for installation in the next outage.
- 02Q295, RHR Head Spray Spool Piece Removal – This project removed the head spray line to eliminate routine outage work scope and alleviate hydrogen explosion concerns for this line.

4) Major maintenance activities beyond modifications included replacement of the entire 250-volt DC station battery # 16, 10 year PM of #12 EDG, replacement of both Recirc pump seals, Torus cleaning and inspection using divers, overhaul of HPCI turbine and cleaning of tape from CRD insert and withdraw lines under the reactor vessel. Reactor vessel activities consisted of location and removal of broken tip detector, changing ten Control Rod Drives.

5) In Vessel Visual Inspection (IVVI), normal fuel shuffle/reload, the replacement of eight control blades and four LPRM's.

RF-22 (3/5/05-4/12/05): Outage Duration was 38 days 22 hours

1) Completed 1457 work orders consisting of the following classifications:
138 Corrective
699 Preventive
313 Elective
97 Design Change work orders
210 Other maintenance work orders

2) 32 modifications were completed during the outage. The major modifications were:

- Replacement of MO –2008, Torus Cooling Return Valve, as found pipe conditions caused this scope to expand from 2 field welds to 17 field welds
- Completion of the ductwork modification in 12 EDG room
- HPCI and RCIC flow control upgrades
- Replacement of 11 Recirc pump motor & repair of 11 Recirc pump

- 11 Recirc Motor power cable replacement
- Replacement of RHR 14 pump motor
- Repair to CRD 38-13 insert line
- Replacement of FW 32 and CV's 1095 A/B, Condensate Recirc & Bypass Valves
- Removal of CGCS & RHR Head Spray piping and valves & capping of primary containment penetrations

3) Major maintenance projects included:
- Replacement of 11 Condensate Pump & Motor
- MAGIC inspection of the Main Generator
- Major inspection of "B" LP Turbine, scope expanded to "A" LP Turbine based on "as found" conditions in the "B" Turbine
- Replacement of 12 Reactor Feed Pump rotating element
- Clean out of bottom head drain line
- Reactor Vessel Shroud inspection
- Reactor Vessel Steam Dryer inspection
- Dog bone replacement on both condensers

<u>**RF-23** (3/14/07-4/28/07)</u>: **Outage Duration was 45.8 days**
1) Completed 1453 work orders consisting of the following classifications:
9 Corrective
947 Preventive/Surveillance
160 Elective
15 Design Change work orders
322 Other maintenance work orders.

2) 16 modifications were completed during the outage. The modifications included:
- Replacement of 12 Recirc pump and motor
- Turbine System Wiring Replacement to address cable aging
- Replaced #11 and 12 Reactor Recirc Pump cables (Bus to MG Set to Pump)
- New Main Generator Voltage Regulator Replaced turbine slop drains
- HPCI steam void mod
- Replaced SDV level switches
- Replaced MO 2373/2374 steam line drain valve
- Modified SRV E, F, G & H Div 2 Controls for Appendix R
- Added 1AR and LC Control Room Ammeter

- Recirc MG brush holder mod to support online brush replacement
- Replaced 4 obsolete Rotork Actuators with new Limitorque Actuators

3) Major maintenance projects included:

- Primary Systems
  - Torus drain down and coating
  - #12 Reactor Recirc Pump rotating element replacement and motor replacement
  - #12 RHR Pump overhaul
- Diesel Generators
  - 12 year PM on #12 EDG
- Secondary system
  - #12 Rx Feed Pump motor refurbishment
  - #12 Condensate pump and motor replacement
- Major Testing
  - ILRT (Integrated Containment Leak Rate Test)
  - ECCS Test (Emergency Core Cooling System Test)
- Refuel Floor
  - 150 fuel bundles and normal IVVI scope
  - Steam Dryer Underside Inspection
  - 16 new Control Blades replaced
  - Jet Pump Hold Down Beam UT inspection
- Turbine Floor
  - Generator re-wedge
  - Disassemble and inspect LP A Turbine
  - PM Front Standard (MHC)
  - Turbine system wiring inspection and partial replacement
  - Automatic Voltage Regulator Replacement
  - #5 bearing replacement

RF-24 (3/14/09-5/8/09): **Outage Duration was 55 days 17 hours**

1) Completions of 2220 work orders consisting of the following classifications:

112 Corrective
1328 Preventive/Surveillance
319 Elective
32 Design Change work orders

429 Other maintenance work orders.

2) Outage Scope Major Work

- LCM/EPU Project Modifications
  - High Pressure Turbine Replacement
  - Low Pressure Turbine Modifications on A and B
  - Cross Around Relief Valve (CARV) and Piping replacement
  - Isophase Bus Duct Cooling Mod
  - Power Range Neutron Monitoring Installation
  - Extraction Steam Bellows Replacement
  - Feedwater Heater Valve replacements
- Primary Systems
  - Replace Rotorq actuator on MO 1749
  - 121 Scam Solenoid Pilot Valve replacements
- Diesel Generators
  - 12 year PM on #11 EDG

RF-25 (3/5/11-5/25/11**)**: **Outage Duration was 81 days 10 hours**

1) Completions of 1849 work orders consisting of the following classifications:

11 Corrective
1328 Preventive/Surveillance
25 Elective
32 Design Change work orders
38 Other maintenance work orders

2) The following major work scope was completed during this outage.

1. LCM/EPU:
   - Steam Dryer replacement.
   - Condensate Demineralizers and Control Panel replacement.
   - Main Transformer Replacement.
   - Generator stator and rotor rewind.
   - Exciter replacement.
   - 14, 15 Feedwater Heater replacements.
   - New level columns and transmitters- level tree improvement to allow flushing and hydrolazing.
   - Remaining Feedwater heater dump and drain valve replacements (4).
   - #11 and #12 Heater Drain Piping and nozzle replacement.
   - Moisture Separator Drain Tank Cooling.

- Stator Cooling Hx/Filter Replacement.
- Bentley Nevada vibration system (put probes on Gen bearings).

2. Primary Systems:
   - Replaced approximately 1/3 of the fuel bundles.
   - Replaced 4 LPRMs.
   - Replaced 12 Control Blades.
   - Vessel Ultrasonic Testing.
   - Scram Valve Teflon seat replacements and HCU PMs (1/8th).
   - #11 Recirc Pump Seal Replacement.
   - Safety Relief Valve Replacements (2 top-works, 2 bodies).
   - #12 RHR Hx Cleaning and head recoating.
   - Division 2 RHR Service Water piping replacement.
     - ✓ Div 2 in Intake (40').
     - ✓ Div 2 in Tunnel (100').
   - Replaced Primary Instrument Manifolds with Sweglock design.
   - Modified RCIC MO 2076 to close on torque.
   - Replaced the flow elements on the HWC system with Coreoles instruments.

3. Electrical Systems:
   - App-R/MSO Mod.
   - Medium Voltage cable testing and replacement
   - MCC 141 Cable Replacement (EC).
   - #11 Core Spray Pump Cable Replacement.
   - #16 Battery Replacement.
   - #12 Battery Replacement.
   - 4 Year Minor PM on #12 EDG.

4. Secondary System:
   - #12 Circulating Water pump and motor refurbishment.
   - Outboard MSIV 86A actuator, Inboard MSIV 80D actuator replacements.
   - Inboard MSIV 80A Internals refurbishment.
   - Outboard MSIV Overhaul and Disk Pack Replacement with better satellite – contingency.
   - Tritium Mitigation Mod.

5. Turbine:
   - Turbine wiring replacement (3rd Phase).

- All Stop Valves and Control Valves Refurb
- CIV 1, 4 Refurb.
- BPV #12 Refurb.
- Mechanical Vacuum Pump Overhaul.
- Installed leak tight internals on the MS Dump Valves.
- Overhauled the actuators on the MS Drain Valves (HT parts EC).
- MSR Level Instruments (New columns and Transmitter).
- #12 FW Heater Level Instruments.
- Condenser Howell level column and transmitter.
- New Main Generator HV Bushings.

RF-26 (3/2/13-7/19/13): **Outage Duration was 139 days 5 hours**

LCM/EPU subprojects issues drove the critical path and duration of the outage.

1) Completed 3405 work orders consisting of the following classifications:
480 Corrective
2065 Preventive/Surveillance
318 Elective
68 Design Change work orders
16 T-Mods
461 Other maintenance work orders.

2) The following major work scope was completed during this outage.

LCM/EPU

- New 13.8 KV switchgear for Bus 11 and 12
- Replace 1R and 2R Transformers with 4 KV and 13.8 KV windings
- Replace Recirc MG Set Motors and Exciters with 13.8 KV
- Replace RX Feed Water Pumps with 13.8 KV
- Replace Condensate Pumps with 13.8 KV
- Install Room Coolers for Condensate Pumps
- Replace 13A/B Feedwater Heaters
- Replace 11 and 12 Feedwater Heater Nozzles
- Install Moisture Separator Drain Tank Cooling

Site Projects
- Install 2RS Transformer Gas analyzer
- Replace #11 125 vdc safety related battery
- Replace #13 250 vdc safety related battery
- Replace Turbine Building Roof
- Replace Primary Instrument valve manifolds
- Partially install RP remote monitoring Camera system
- Install On-Line Noble Chemistry system
- Modify HWC to support On-Line Noble Chemistry
- Replace RHR Power Cable (4) and Core Spray Cable
- Overhauled and rebuilt 3 RHR Pumps and 2 Core Spray Pumps
- HPCI steam supply valve timing modification
- Remove/Disable air for 6 testable check valves
- Install Alternate Spent Fuel Pool Cooling
- Install lower 4 KV HELB Barrier
- Modify RPIS Power Supply configuration
- Paperless recorder installation in control room
- Repaired underwater Torus coatings

Diesel Generators
- 6 year PM on 12 EDG
- 4 year PM on 11 EDG
- EDG Fuel Oil Internal Tank and piping Inspection
- T-Mod installation for EDG Fuel Oil Supply for EDG Availability
- Agastat relays on both EDG's
- Other Corrective/Deficient WO's and testing

Reactor/Primary Systems
- Replace 6 LPRM's
- 264 with additional 82 IVVI inspections
- Replaced remaining 5 original Dry Tubes
- Replaced #11 and #12 Recirc Pump Seals
- Removed new Steam Dryer Instrumentation
- Replaced 6 SRV's
- Replace 20 HCU Accumulators
- HPCI Turbine Major Overhaul

Turbine

- Control Valve Servo Enclosure Overhauled
- Steam Seal Regulator Overhauled
- Bypass valve Control overhaul
- Pilot valves and Intercept valve test transmitter replacement
- Emergency Trip Valves and Backup Over-speed Trip Device overhaul
- Overhaul Vacuum Trip 1 and 2
- Replace and calibrate Acceleration Relay
- Replaced Turbine Front Standard Wiring
- Overhauled Torque Tubes

Secondary System

- Swap 1 inboard and 1 outboard MSIV Actuator
- MSIV PM's and testing - 19
- CST Internal Coatings Inspections
- Decay Line and CST Buried Piping Inspections
- Buried Fire Protection valve replacements (3)

Valve Scope

AOV Scope

- AOV Internal rebuilds – 40
- AOV Operator Rebuilds – 42
- AOV Viper Test – 58
- AOV Drop Test – 19
- AOV Positioner Calibrations – 26
- Non-Program valve rebuilds – 45

MOV Scope

- MOV PM's – 76
- MOV Viper Test – 49
- MOV Operator Rebuilds – 8
- MOV Internal Rebuilds – 8

Misc. Valve Maintenance

- Internal Check Valve Maintenance – 66
- Valve repacks – 11
- CRD/HCU Internal Valve Maintenance 61

To the extent this question is requesting an explanation about how we updated our as-built drawings as a result of each outage, please see our response to DOC Information Request No. 27.

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Date:	May 7, 2014

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☒ **Public Document**

Xcel Energy
Docket No.: E002/CI-13-754
Response To: Department of Commerce Information Request No. 041
Requestor: Nancy Campbell, Chris Shaw & Steve Rakow
Date Received: December 10, 2013

Question:

Reference: Page 49 of Direct Testimony of O'Connor

General Electric provided two implementation schedules for completing Monticello LCM/EPU, first one with outages in 2009 & 2011, second one with outages in 2011 & 2013, with Xcel selecting the first one. In the end, the Company required outages in 2009, 2011 and 2013 to complete the Monticello LCM/EPU project, does that mean the 2011 & 2013 second schedule would have been a better choice to allow the Company more time to better plan and reduce outage costs? Please explain.

Response:

The Company does not believe selecting the 2011/13 schedule would have been a better choice and our choice to proceed with the 2009/11 schedule was a reasonable choice under all of the circumstances.

In 2006 we made the choice to move forward with implementation outages in 2009 and 2011 based on the best information we had available at the time in order to satisfy our goal to meet the anticipated 2010 need. As the scope of the Program was conceived in 2006, we believed that the work could reasonably be completed in two outages. We recognized at the time that implementation was time-sensitive. We chose to multi-track the LCM/EPU Program, 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.

At the time we began the initiative we believed we could obtain our NRC operating license amendment in 2010 and completing the upgrades in 2011 would achieve the greatest value for customers.[1] The forecasted resource need we were seeing at the time also meant that Xcel Energy had a significant incentive to proceed promptly and implement the Program sooner rather than later. We decided to proceed with 2009/11 implementation plans on multiple tracks simultaneously.

We note that our decision to implement the Program beginning with the 2009 outage was consistent with our expectations at that time of the work to be done. The 2009 outage was implemented only two months after we received the Certificate of Need and went relatively well. While additional planning time may have helped us better forecast the magnitude of the work, rather than proceeding directly to the 2009 outage, it requires a good deal of speculation to suggest that the costs or schedule would have been materially different had we waited.

The primary change of a 2011 and 2013 outage from what actually happened is that the 2009 work would have awaited the 2011 outage. Adding that work to the 2011 outage, which already had a substantial scope, could have created the same risk of completing the work in three outages without the benefit of having the plant work completed once the license was finally received at the end of 2013.

The design efforts for 2011 continued through 2009 and 2010 for key outage activity in 2011 and what eventually became 2013, even though we implemented work in the 2009 outage. We do not believe that undertaking the 2009 outage implementation interfered with or delayed our preparation for the remainder of the work.

Also, while there would have been some more time to plan for implementation if we had not done work in 2009, this is not a guarantee of lower costs. As we discussed in IR 20, detailed planning helps to better predict time and effort, but it does not necessarily reduce costs. This work was necessary in either event.

Based upon our actual experience (planning for 2009/2011 implementation and then adding a third outage), we are concerned that had we planned for 2011/2013 implementation, we may have ultimately had to delay completion to a third outage just

[1] At the time we submitted the NRC EPU license request, the NRC targeted a review period of approximately 12 to 18 months. However, as discussed in the direct testimony of Timothy O'Connor on pages 51-57, that process was delayed for several reasons. One specific delay related to concerns raised by Advisory Committee on Reactor Safeguards (ACRS) committee on Containment Accident Pressure (CAP) impacted all license applications, including the Monticello EPU license application. The recent new NRC policy resolved the open technical concern associated with CAP. Our EPU license was just granted on December 9, 2013, or 5 years after our submission.

as occurred with the current start date due to the magnitude of the work completed and some of the issues encountered during implementation.
While the 2011 outage faced issues because of the need to rework design, and this created pressure as we moved into that outage, it is not clear that deferring the 2009 work to 2011 and expanding the 2011 outage scope would have relieved that pressure. Indeed, because of the CapX2020 work implemented at the Monticello substation in 2011, it is not clear that we would have been able to coordinate significant additional work at that time.

While proceeding with the 2011 and 2013 schedule was one of several reasonable alternatives available to the Company, the decision to move forward with the 2009 and 2011 schedule, was also a reasonable alternative to have selected, particularly given the forecast resource demand at the time we made the decision and our reasonable expectation of receiving an uprate license in 2010. And because the work that required the most effort was eventually completed in 2011 and 2013, we do not think there would have been any material cost savings by foregoing the work that was completed without problems in the 2009 outage.

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Xcel Energy

Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	019
Requestor:	Nancy Campbell, Chris Shaw & Steve Rakow		
Date Received:	December 10, 2013		

Question:

Does the Company believe it may have been more helpful to do a more detail design upfront for the LCM and EPU projects, rather the conceptual design which resulted in significant scope changes in the middle of construction period? Please explain.

Response:

In the nuclear industry, it is standard practice to commence work on major capital projects on the basis of high-level conceptual designs. The practice of performing conceptual design is consistent with industry best practices such as INPO 009-05, Excellence in Nuclear Project Management and Xcel Engineering and Project Management procedures.

Detailed design takes years and significant cost to develop and it would be infeasible in many instances to wait until completion of detailed design. Further, there are many areas in an operating nuclear plant that are inaccessible during normal operations due to high radiation. This means that those areas cannot be accessed for detailed design review and preparation and makes it difficult to identify interferences and other design details.

In the case of the LCM/EPU Project, we believe that the use of the conceptual design approach was appropriate, consistent with industry practice, and prudent. At the time we developed and commenced the Program (2006-08), we were faced with the need for substantial additional baseload capacity and high natural gas prices and assessed that delay was not in our customers' interest under those circumstances. Mr. Alders' Direct Testimony in this proceeding provides an extended discussion of the resource planning considerations that influenced the Company's timing and approach for the Program.

If we had waited until completion of the detailed design, it would have had the effect of delaying our Certificate of Need and NRC license amendment requests and would ultimately have delayed or potentially precluded implementation. We note that the NRC's evolving licensing requirements (which require more up-front detailed design) was an important factor in the Company's decision to cancel its EPU upgrades at Prairie Island, as described in the Direct Testimony of Scott McCall and James Alders in our pending rate case, Docket No. E-002/GR-13-868.

We recognize that detailed project design is helpful in defining the scope of a capital project. And we did refine our scope and detailed design as we proceeded in developing the Program. Indeed, it should be noted that we did not face "significant scope changes in the middle of the construction period" as suggested in this question. After the Company decided in 2006 to proceed with the Program, we continued the design phase and worked to refine the scope. By the end of 2007, the overall scope of the Program was substantially set and the modifications actually implemented are consistent with that scope. The evolution of the scope and design of the Program is described in detail in Mr. O'Connor's direct testimony pages 93-139 and Schedules 19-28.

We acknowledge that our forecasting of the costs associated with the final scope could have been better. Our initial overall cost estimate was based upon the conceptual 2006 scope, updated and used for modeling alternatives in the Certificate of Need proceeding was $320-346 million. This overall estimate was reasonably believed to be sufficient for the Program at the time of the Certificate of Need. In hindsight, we recognize we should have foreseen that the final scope would cost more than $320 million but, based on what we knew at the time, we never would have anticipated that the actual cost would be $665 million (as of August 31, 2013), even if we had done a better job of estimation. As Mr. O'Connor testified (page 7), in retrospect, it seems apparent the Program was going to cost more than we forecast and the scope changes arrived at during 2007 meant the costs were going to increase. However, while we now see we could have done a better job of forecasting costs, at the time we were developing the Program, the added costs associated with the 2007 scope changes was not evident and we clearly did not believe that the final costs would approach $665 million. As Mr. Alders' testimony demonstrates, both the $665 million would have been cost effective in 2008 (under all circumstances) and remained cost effective (with carbon) in 2013.

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The Engineering And Design Process

Xcel Energy Nuclear Department

This Schedule was prepared at the request of and under the direction of Timothy J. O'Connor for his use in the normal course of his duties. It provides a narrative description of the engineering and design process used for the Monticello LCM/EPU Program. Design work on nuclear projects is complex and costly, particularly when performed within the confines of an older nuclear facility such as Monticello. The purpose of this Schedule is to illustrate that (1) the modifications on the LCM/EPU Program were carefully planned and followed standard procedures in the nuclear industry, and (2) even with the methodical roll-out of modification design, it was difficult to estimate Program costs in the early stages of design.

A. Detailed Description of Design Process

The initial designs developed to conceptually evaluate the LCM/EPU Program emanated from: (1) a review of the systems and equipment identified on the Long Range Plan ("LRP") as required to be addressed prior to or during the period of extended operation, and (2) identified pinch points that limited the ability of the plant to operate at uprated capacity levels. The process then created solutions to address these pinch points.

Once solutions were identified, the required physical changes were integrated with the LRP items, including those items for which earlier than planned installation made sense. The principle objective of this effort was to prepare the station for an additional 20 years of safe, reliable operation and support the license amendment request for the NRC to operate at the EPU power level. Accordingly, the design process for the LCM/EPU Program integrated the needs of modernizing the plant with the ability to increase output. The design process for physical modifications ensured that the desired level of quality was achieved and the needs of the station were addressed.

1. Evolving process

Design in the nuclear power business is an evolving process that moves the design from conceptual to final. Engineering design development requires an evolutionary approach for two reasons:

- First, initial engineering designs are intended to establish the high level functional criteria. From this functional criteria, performance criteria at a component or system level can be identified through design and licensing bases reviews and impact reviews from station and engineering programs. Once performance criteria are established at the system and component level, required design standards, specifications, calculations and plant specific information are synthesized into a more detailed design. Initial design outputs such as equipment specifications, conceptual layout and routing drawings and calculations are created. Input from field walkdowns, equipment vendors and detail component configurations are necessary to finalize the design for installation.

- Second, new information is frequently identified during the course of the design process that must be addressed in order for the design to perform its function. In the case of the LCM/EPU Program, for example, the large number of simultaneous modifications and the complexity of the plant's systems led to interactions, interferences, and dependencies among the modifications. While reasonable in a Program such as this, these interactions, interferences and dependencies were difficult to foresee until the Company completed a design for each modification. The need for iterative engineering analyses can lead to cost and schedule challenges. The LCM/EPU Program required close coordination between each of the modifications to ensure interactive design efforts did not result in substantial rework.

2. Required procedures

All design work at a nuclear plant is controlled by specific procedures. Safety related designs include all of the following controls, as applicable:

- Determine Design Control Requirements
- Design Interface Control
- Identification and Control of Design Inputs
- Plant Impact
- Design Description, Installation Plan and Test Plan
- Design Reviews (Constructability Review)
- 10 CFR 50.59/10 CFR 72.48 Screenings and/or Evaluation
- Independent Verification/Review
- Design Approval (DRB, PORC & Design Authority)
- Installation and Testing Instructions (Planning)
- Installation Design Support (ECNs & CCNs)
- Turnover (Partial and Final)
- Closeout

If the design is not safety related, some of these controls may not fully apply. Nevertheless, because of the complexity of the design, and the degree of regulatory, industrial safety or economic risk involved, it is generally considered best practices to account for all of these controls.

The engineering and design process at Monticello was designed to accommodate all the modifications in the LCM/EPU Program. It is customary for nuclear projects to be commenced using preliminary designs rather than definitive engineering prior to commencement of the project. The cost and time commitment necessary to prepare the detailed engineering designs and cost estimates is significant. Such assessments and planning can be cost prohibitive and it is exceptionally difficult to accurately estimate costs when all of the scope of a modification is not firm and detailed design work has not progressed.

The design and engineering process followed prescriptive procedures in developing final designs. This is an evolutionary process from conceptual to final design. This process began with a review of basic licensing requirements to identify aging equipment that needed replacement and pinch points that limited the ability of the plant to operate at uprated capacity levels. The process then created solutions to address these issues.

3. Design phases

Engineering and design are completed in various phases, essentially consisting of six stages that the Company was required to follow to ensure nuclear safety and so that designs were the best quality designs possible for the plant.

- *Study Stage.* The study stage provides the preliminary understanding of the Program and allows the Company to understand whether the Program is technically possible. Most nuclear capital projects are commenced during this phase because of the timing and regulatory requirements involved. While this contributes to changes in design as the job is more fully developed, it also allows the Company to move forward with iterative designs and adapt to evolving circumstances.

- *Design Stage.* The design process is initiated by a kick-off meeting for each modification. Each kick-off meeting is generally followed by periodic meetings through the process from conceptual to final design. In this stage, design control requirements are identified, design interface control is established, design inputs are identified and design description is prepared. Supporting design output documents, including calculation analysis and drawings, are prepared to support the process.

- *Design Review Meetings ("DRM") (30/60/90 percent levels).* The first DRM (30 percent) is generally conducted once the scope of the modification is well defined, alternate design solutions are evaluated, and the designer is ready to recommend a design approach for the modification. As the design elements are finalized, most major nuclear projects will proceed to implementation long before achieving an overall 30 percent design for the modification. Further detail is developed at the 60 percent level and greater certainty in the overall design is established. Finally, DRM review to the 90 percent DRM level is intended to thoroughly evaluate the modification, including constructability, installation, and testing.

- *Challenge Boards.* For modifications that are determined to be high risk, a Challenge Board is conducted after the final DRM and prior to the Design Review Board. Challenge Boards are made up of key stakeholders, third party individuals and subject matter experts.

- *Design Review Boards ("DRB").* Once all DRMs, independent design verifications, and, if required, third party reviews on open design issues are completed, the Design Review Board review is conducted. The DRB provides comprehensive review of the modification to ensure that all facets of design, construction, maintenance, testing, and operations are considered during development of the modification package.

- *Plant Operating Review Committee ("PORC").* Finally, senior members of Monticello's plant staff, including the plant manager, are required to provide final sign-off on all designs. The Chair and the Vice-Chair that serve on the PORC are appointed by the plant Site Vice President.

- *Final Design Approval.* After all reviews are complete, the final design approval is completed by the Design Engineering Supervisor/Design Authority.

B. The Design Level Required for an Accurate Cost Estimate

In the context of working in an operating nuclear plant, it is uncommon for projects to be undertaken with up-front detailed analysis. It is normal for designs and scope to evolve as a project progresses through the complex and multi-level design process. LCM/EPU Program work required the replacement of major components, often located in difficult and inaccessible areas, which makes complete design on all modifications before any implementation occurs infeasible. Each of these replacements or modifications must be completed in an operating nuclear power plant with limited space for large components. In effect, this requires the custom design of new components to fit in the current plant facilities and the removal and rerouting of large amounts of piping and wiring to access and accommodate the changes. In the boiling water reactor environment, there are many areas of the plant that cannot be accessed at all while the plant is in operation, making it even more challenging. Temperature and radiological dose are generally the reasons areas are not accessible. In addition, vital areas such as critical switchgear rooms are not accessible in any mode of operation (even shutdown) due to the potential to impact safety adversely. Special controls and protections must be in place before work in these rooms is allowed.

Design would have to proceed to a relatively advanced level in order to lessen the risk of a cost estimate being inaccurate. The first step in reaching such a level would be to determine specific design controls to be applied to the modification. In the case of the major modifications for the LCM/EPU Program, independent design review or independent design verification is required. At the commencement of this level of design work, the Responsible Engineer or Project Manager notifies potentially impacted departments that design work is started. The notification normally includes the following:

- Training Center
- Operations
- Maintenance
- System Engineering
- Supply Chain
- Procedures Group
- Configuration Management
- Management Sponsor (if not already listed above)
- Manager, Fleet Simulator Training
- Program Engineering

The design starts once the quality classification and applicable design controls are established. Design inputs are identified and routed to the organization for impact reviews. Applicable codes, standards and specifications that were used in the licensed

Plant design are identified and made available to the External Design Organizations. Design reviews and field walkdowns, where available, are completed as required by procedure. The design requirements are assembled, controlled, and maintained to provide a basis for verifying that the implemented design meets design requirements. Calculations required to support the modification are performed; and design output documents, such as drawings, specifications, and requirements for installation, inspection, and testing, are prepared.

Next, design reviews are performed to ensure that the design accomplishes its intended function and meets the established design requirements. Independent verification is performed before design output documents are released. When an outside engineering firm is contracted to perform design activities, responsibilities and interfaces are clearly defined. These responsibilities can be defined in specifications, the project plan, or both. Responsibilities, interfaces, and hold points are approved by the Company and agreed to by the contracted engineering management. The Company design engineering organization, as the Design Authority, retains responsibility for safe and reliable plant design.

As the design process proceeds, all necessary design output documents as follows are created:

- Design drawings
- Associated calculations
- Design Description
- Affected Document List (ADL)
- Affected Equipment List (AEL)

When the design is sufficiently developed any long-lead material/equipment is ordered. Material/equipment is not to be ordered during the design phase unless the expenditure was authorized by the project review group for major modifications or the Engineering Supervisor for minor modifications. The Responsible Engineer ("RE") has the Design Description, and associated design output documents reviewed or verified. All Preparer, Reviewer, and Approved signatures, as required, are affixed to each document or document cover sheets.

The RE may have the Modification Package reviewed by a knowledgeable individual (i.e., Peer) or a team of knowledgeable individuals named by the Design Authority. Multiple Design Review Meeting ("DRM") reviews are performed during the design phase and ultimately management review and approval is required. Design has to advance to at least a point where many DRM reviews have been conducted in order to develop cost estimates that have substantially less risk of being inaccurate as compared to cost estimates created at the beginning of design process.

C. Completion of Design

At the time the design is essentially complete, Issued-For-Construction ("IFC") drawings are prepared. This should typically occur 9 to 12 months before implementation. These IFC drawings form the basis for the installation planning. At this time a more accurate estimate of project costs can be made because reliable material takeoffs can be generated and used to determine installation labor. Equipment and material costs can also be reliably determined. To get to the IFC stage for an entire Program with the complexity of the LCM/EPU requires 4 to 6 years, which is why the design work is done in parallel with field work.

Even after IFC drawings are completed, construction often reveals that design needs to be modified to accommodate as-found conditions. While the Company attempts to minimize this, in efforts as large and complex as the LCM/EPU Program this is inevitable. Changes at this stage are called field design changes or just field changes. They are primarily driven by accessibility, interferences and installation complexities. The complexity of any particular change dictates the amount of time and effort required to resolve it. Simple changes may require only a few hours to address while the most complex changes required hundreds of hours of effort. Field design changes often require reanalysis, preparation time, review time, and appropriate time for approval.

In general, throughout the LCM/EPU Program, the Company used the same process to identify and implement necessary field changes, which can be broken down into three categories: basic, intermediate and complex. For the most complex changes, a change in one system impacted other nearby or related systems, thereby requiring reanalysis of a number of systems. This analysis was highly iterative. Each time a change was proposed and analyzed, the Company confirmed that the systems worked together in accordance with applicable standards. This sometimes required multiple rounds of reanalysis, as the "ripple" effects of a particular change were addressed.

For example, when the condensate demineralizer vaults were accessed, it was discovered that the wiring was substantially degraded and not able to be re-used as originally planned. Another example was the interference in moving the new equipment through the access hatch. The 3" ESW line had to be re-routed to provide adequate clearance for the new equipment. The 13.8 kV switchgear was not able to be installed close to the Feedwater Pumps due to space limitations and had to be relocated. After evaluating multiple options, the switchgear was relocated to the Hot Machine Shop location. This in turn required the Hot Machine Shop to be relocated to the Radwaste Building. None of these could have been discovered in a detailed up-front engineering process.

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☒ **Public Document**

Xcel Energy
Docket No.: E002/CI-13-754
Response To: Department of Commerce Information Request No. 107
Requestor: Chris Shaw, Nancy Campbell
Date Received: April 25, 2014

Question:

Is there a Monticello Site Team with experienced engineering, procurement, construction and project management assigned to the site full time? If so, please identify all of the members of the team over time and the years for which they served on the team.

Response:

Yes. The Monticello Site has experienced resources available to it who are dedicated to the functions described in this question for both (i) ordinary operations and maintenance, and routine capital projects, (ii) larger capital projects that require additional dedicated resources, and (iii) external resources when necessary to supplement our resources to ensure timely and appropriate completion.

Each of Monticello and Prairie Island Sites maintain a staff on Site to undertake necessary activities. The Company has provided a detailed discussion of its staffing needs at its nuclear plants in response to DOC Information Request No. 1159 in our current rate case, Docket E002/GR-13-868, a copy of which is provided as Attachment A to this response. That answer provides detailed information of the types and numbers of employees we have available for the Sites.

As it pertains specifically to implementing operations and maintenance and capital projects, each of our Sites will have available to them project management structure includes project managers, engineers, schedulers, cost control personnel, construction management, planning, material procurement and licensing, while the corporate structure consists primarily of project management.

Monticello maintains a staff on site to support the operations and maintenance of the plant, as well as to deploy those routine capital projects that can be supported by the available resources. This is an efficient way of ensuring that the plant can support recurring and expected projects that arise with an operating nuclear plant. In addition, dedicated resources are made available to the Monticello Site for major capital projects (those that require more dedicated resources than can be reasonably handled by the Site personnel) are dedicated to those projects.

We try to design our full-time staff to be adequate to deploy the majority of the capital projects and O&M work laid out in our long-range plan for each of the Sites. Generally, the on-Site staff focuses on recurring, routine and smaller projects that can be expected in the normal course of business. For example, if we have a smaller modification to one of the plants arising out of our long-range plan, we will assign a project manager from the Nuclear Projects organization to oversee the project and deploy our internal design engineering resource to develop the modification If the project is sufficiently large or there are too many competing demands for our internal engineers, we would consider retaining a staff augmentation engineer or deploy an external design organization (with proper oversight by the Company) for completion. For projects of larger scope and complexity, we generally rely more on our Nuclear Projects organization to provide leadership in obtaining and deploying the additional resources necessary to complete the work.

As described in our answer to DOC Information Request No. 78(h), the Company recognizes that for larger capital projects it is appropriate to provide dedicated project management resources to the Site through the capital projects organization. The Nuclear Projects organization also provides project management for common projects that affect the entire fleet. Computer software upgrades, Cyber Security requirements, and Fukushima impacts are just a few of the projects that would be managed by the corporate office. When a major project is underway, resources assigned from the Nuclear Projects organization will be dedicated to the particular site for the duration of the particular project.

This limits the risk that the Site projects team will become distracted from its core responsibilities to ensure safe and reliable ongoing operations and maintenance. It also ensures that the major project is given the resources necessary to complete the project in a timely and cost-effective manner.

Finally, for larger capital projects (such as the LCM/EPU Program, the Steam Generator Replacement Project at Prairie Island, and the upcoming Fukushima compliance projects), it is normal and expected that we would supplement our workforce with contractors and consultants. As described more fully in our response to DOC Information Request No. 108, it is a more appropriate allocation of resources to rely on external resources for major capital projects and it is standard in the industry to deploy external resources for the duration of such projects.

For purposes of this question, we are providing employee names and titles for those employees who were available to assist in connection with the LCM/EPU Program. The following chart provides a description of the major categories requested in this question and provides the identification of functions and resources for both the Site and the LCM/EPU Program. In addition to this summary chart, the Company has produced detailed organization charts for the LCM/EPU Program in the document production in response to DOC Information Request No. 48. These organization charts can be found at document numbers NSP-0027505- 0028419. The personnel shown on these organization charts were dedicated to the Monticello Site for the duration of their work on the Program. The dedicated Monticello Site team and the nuclear Project team worked together closely on the LCM/EPU Program to ensure that the project was acceptable to the Site and that the project met all plant requirements.

Function	**Monticello On-Site Projects Team**	**Capital Projects Team Dedicated to Monticello for LCM/EPU Program**
Overall Project Management, including subproject Project Managers (PM)	Pat Burke Manager of Site Routine Projects from 2007-2012 Darren Helm Manager of Site Routine Projects from 2012-Present Mike Mohs – PM from 2009 thru 2012 Tory Strege – PM from 6/1/11 - 4/10/14 Marissa (Carpenter) Martinson (Intern) - 5/11/2009 - 3/1/2012 –	Al Williams Manager of Capital Projects from 2006-2011 Pat Burke Manager of Capital Projects in 2011 John Bjorseth Manager of EPU/LCM from 2012-2014 Sara Cotter – PM from 05/08 thru 09/13. Jason VanOverbeck – PM from 01/07 thru Present

Function	**Monticello On-Site Projects Team**	**Capital Projects Team Dedicated to Monticello for LCM/EPU Program**
	became a full time Xcel as PM on 8/27/12 thru Present. Lee Hammel – PM from3/13/2009 thru Present. John Gushue – PM from 2007 thru Present Anne Ward – PM from 2004 thru 2005 Joe Pairitz – PM on 12/23/07 thru 11/25/11 Ron Siepel – PM from 12/23/07 thru 1/27/2008 Marv Engen – Retiree was a PM from 2005 – 2007 Melissa Limbeck – PM from 12/23/07 thru 1/1/11. Changed jobs within the project but stayed with the overall EPU/LCM Project. DuWayne Wacha –PM from 12/1/08 thru 7/1/11. Tom Ginter – PM	Steve Hammer – PM from 2006 thru Present

Function	**Monticello On-Site Projects Team**	**Capital Projects Team Dedicated to Monticello for LCM/EPU Program**
	from9/24/12 to Present Joel Seela –SR Project Coordinator – 12/26/06 thru 9/10/10. Scott Hastings – SR Project Coordinator from 12/4/2006 thru 4/16/2010.	
Overall Project Management	Pat Burke 2007-2012 Darren Helm 2012-2014	Al Williams 2006-2011 Pat Burke 2011 John Bjorseth 2012-2014
Engineering and Design	John Grubb 2004-2009 Nate Haskell 2004 – 2013 Josh Ohotto 2009-2012 Rick Zyduck 2012-2014 Mark Lingenfelter - 2014	Rick Rohrer -2007-2008 Randy Garding – 2008-2011 Scott Quiggle -2009-2012 Jim Gausman – 2010- 2012
Procurement	Jeff Nelson 2001-2014	Jeff Nelson 2006-2014
Construction	Gary Gunther 2006-2007 Gene Foote 2008-2014 Darrel Ostendorf 2000-2014	Gary Gunther – 2006-2007 Gene Foote – 2008-2014 Darrel Ostendorf 2008-2014 D&Z – 2008-2014 Bechtel – 2011 (June) -2013
Work Management, Scheduling and Estimating	Gary Gunther – 2006-2007 Don Bosnic – 2008-2012 Dwight Campbell 2012 – 2014	D&Z-2008-2014 Bechtel– 2011 (June) -2013
NRC Compliance and	Doug Neve – 2006-2007	Steve Hammer -2006-2014

Function	Monticello On-Site Projects Team	Capital Projects Team Dedicated to Monticello for LCM/EPU Program
Licensing	John Fields - 2008 Steve Speight – 2009-2010 Pete Kissinger – 2011-2014	

Preparer: Mark Schimmel
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Department: Nuclear
Telephone: 612-215-4613
Date: May 7, 2014

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Xcel Energy
Docket No.: E002/GR-13-868
Response To: Department of Commerce Information Request No. 1159
Requestor: Angela Byrne, Nancy Campbell, Dale Lusti and Sachin Shah
Date Received: March 18, 2014

Question:

Reference: Timothy O'Connor Direct Testimony, Page 94 – Chart 1, Headcount Additions by Function

A. Please explain the need for the 41 additional headcounts for engineering – what specific type of projects will they be doing (that is different from operations and maintenance which is under separate functions).

B. Please explain the need for the 30 oversight additional headcounts. If oversight is equivalent to supervisor, that means 4.2 employees to 1 supervisor (156-30=126/30=4.2), please explain why the 1 supervisor/oversight to 4.2 employees is reasonable.

Response:

A. We previously provided information that we believe is generally responsive to this request. The question is addressed in detail on pages 2-3 of Attachment A to this response, which is a copy of our response to Information Request XLI-120-Attachment A in this proceeding. With this request we are providing additional information related to the engineering groups.

At the outset, we note that we have organized our response to first describe the differences between our engineering function and our operations and maintenance function, from the Nuclear business unit's perspective. From there we address the reasons we added engineering headcount from an organizational perspective (i.e., generating unit) and functional perspective (e.g., different types of engineers).

Engineering Function Compared to Operations/Maintenance Function
We believe it would be helpful to understand the differences between the functions performed by our engineers as compared to operators and maintenance contributors by first seeing that 85 percent of our engineers are in three functions: Design Engineering, Systems Engineering, and Engineering Programs.

Table 1

Change in Engineer Employee Counts By Function, Actual 2012 to Budgeted 2014	**Actual 12/31/12**	**Budgeted Test Year 2014**	**Net Increase (Decrease)**
Design Engineering	62	70	8
Systems Engineering	62	86	24
Engineering Programs	63	61	(2)
Probabilistic Risk Assessment (PRA)	0	10	10
Fuels Engineering	19	20	1
Engineering Support / Other	13	13	-
Total	219	260	41

Design Engineering involves mechanical, electrical and civil engineering related to our nuclear generating units. Our design engineers generally design modifications to address mandatory regulatory requirements, equipment obsolescence and equipment reliability issues not resolvable through maintenance. Design work also includes maintenance of station drawings, design basis documents and the NRC's Updated Final Safety Analysis Report (UFSAR) as well as maintenance of the station's calculation control program and margin management program. Design engineers also support implementation of the Company's corrective action program.

Systems Engineering involves work on the reactor, safety systems and balance-of-plant systems. Our systems engineers generally perform tasks such as performance trending, health assessments, preventative maintenance specifications, maintenance rule compliance assessments, long-range planning item identification and corrective action program tasks.

Engineering Programs involves work on equipment reliability, inspections and materials, and long-term plant programs and regulatory programs. Engineers within this function perform such work that includes non-destructive examination of installed piping, flow accelerated corrosion examinations, examinations of piping for microbiological attack, welding program and implementation oversight, in-service testing of pumps and valves, repair and replacement plan preparation, in-service inspection, fire protection and 10 C.F.R. § 50, App. R compliance (NRC regulations), cable aging management, equipment qualification, motor operated valve program, air operated valve program, check valve program and relief valve program implementation. Program engineers also support the implementation of corrective action program.

In contrast, the Operations functions are generally involved in operating the generating plant, including managing and monitoring the operation of the reactor and equipment within established safety margins using instrumentation and other tools. Maintenance functions are generally involved in mechanical and electrical maintenance on plant equipment; maintenance on instrumentation and controls; and maintenance support of construction work. This includes both corrective and preventative maintenance.

Reasons for Adding Headcount– Organizational Perspective

We believe to best understand our reasons for adding engineering headcount involves looking at our decision making process from an organizational perspective as well as a functional perspective. We also believe the value derived from adding this headcount can be better understood when looking through the differing lenses offered by these two perspectives.

When we refer to the "organizational perspective", we mean the place within our organization that the engineers are being added to, such as Prairie Island generating units, the Monticello nuclear generating unit, or fleet/corporate oversight. From the organizational perspective, the largest increases are occurring at Prairie Island (26/41) and in the fleet/corporate oversight group (12/41). The need for the staffing increases at Prairie Island and fleet oversight engineering groups is summarized as follows:

- **Prairie Island** – increasing the number of engineers was considered to be needed to address recent turn-over at the plant due to retirements. As discussed below, prior to these retirements, the unit was under-staffed and the retirements furthered our understaffed position. As a result, we needed to add headcount to rebuild staff levels and resolve the backlog of work.

By way of background, we benchmarked engineering staffing levels at other utilities and plants of similar size to Prairie Island (i.e., dual unit Pressurized Water Reactors, or PWRs). We then performed a gap analysis for those areas with notable differences from the benchmarked levels. Our benchmarking effort, coupled with the gap analysis, supported the addition of engineers in various areas.

Prior to this point, we were addressing our personnel gaps with contractors. After performing the analysis described above, we elected to take a different approach by hiring engineers as full time employees. We believed this would allow us to create a smaller ratio of engineers to systems and provide more dedicated technical support to each system. Additionally, we believed we could improve the personnel pipeline for long-term operations, which is important given the time and effort required to attract and develop engineers with the qualification and experience levels necessary for reliable sustainable performance.

In closing, we note that from a benchmarking perspective, the 2014 budgeted engineering staff levels at Prairie Island are still below the industry average based on a recent survey of other two-unit plants.

- **Fleet/Corporate Oversight** - staffing increases were planned to help respond to increasing regulatory requirements in the engineering area, and to build more in-house engineering competencies and reduce reliance on higher cost contract engineering resources. The number of regulatory inspections for equipment reliability, that are the responsibility of our engineers, has become increasingly resource-intensive. The man hours necessary to prepare for each inspection, as well as provide support during the inspection, and then the follow up afterwards, have also steadily increased. Several of the inspections are not only large in scope to begin with, but also have increased in intrusiveness and resource requirements the last few years. Nuclear is subject to inspections by not only the NRC itself, but also by the industry group INPO, Nuclear Electric Insurance Limited (NEIL), and state oversight Authorized Nuclear Inspectors (ANI). The staffing increases in Fleet/Corporate Oversight are in response to these industry changes.

  As an example of resources needed for the larger inspections, all of the Component Design Basis Inspection (CDBI), Triennial Fire Protection, Force-on-Force, Problem Identification and Resolution (PI&R), NRC Modifications /CFR 50.59 require an internal Focused Self Assessment (FSA)

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to be done to the full scope of the inspection, in advance of the actual inspection. Any issues identified by the FSA must be resolved prior to the inspection. Also, for these large inspection scopes, considerable resources are required to support the pre-inspection document requests. During the execution of the inspection, dedicated full time engineering support is required to ensure timeliness of responses to the inspector requests for information. Finally, any issues that are identified may require engineering resources for operability or license compliance evaluations. We can provide more detailed data on the scope of each major regulatory inspection that we face in the test year 2014 operating cycle.

Similar to our efforts at Prairie Island, we benchmarked our engineering levels within the Fleet/Corporate Oversight organization to better understand our staffing needs. We found an increase in staffing is needed to perform consistent with the Governance-Oversight-Support-Perform (GOSP) model supported by INPO. This model ensures standards are maintained at a high level, which generally yields lower long-term operating costs.

We are adding four engineering positions at Fleet/Corporate Oversight- one in Systems, one in Design, and two as general fleet/corporate oversight - to provide future bench strength for the nuclear fleet as a whole, and reduce reliance on contractors to fill key positions when they open up. Benchmarking has shown this level of staffing for these positions is essential to assure compliance and consistency with industry best practices, and to support both plants for the hundreds of inspections, evaluations and audits performed by the various nuclear stakeholders.

The positions added to date have already begun to improve the technical rigor and product output of our engineering work at both plants. Our expectation is that increased staffing in fleet engineering will (a) raise the overall engineering performance levels beyond regulatory compliance, and (b) allow Nuclear to become more proactive at detecting issues before they require significant corrective actions.

Reasons for Adding Headcount– Functional Perspective

As Table 1 above shows, the majority of the total increase in engineering headcount is occurring in three functional areas: Design Engineering, Systems Engineering, and Probabilistic Risk Assessment (PRA). The following summarizes the reasons for the increases in those areas:

- **Design Engineering** – for this function, we are proposing to add eight engineers. These positions are necessary to provide increased technical oversight of external design organization activities on major capital modifications as identified by INPO, our in-house Nuclear Oversight organization and the independent Management and Safety Review Committee. This added headcount will also help maintain and reduce design backlogs and corrective action backlogs so that plant risk is reduced. Key design area programs such as High Energy Line Breaks (HELB), External Flooding, Tornado Missile Protection, and Station Blackout have undergone additional NRC focus due to Fukushima events in 2011. These areas have also created additional design organization workload to own and assess compliance with the new regulatory requirements and the impact on our licensing and design bases. Simply translated, the required man-hours to perform this work showed a shortfall in required resources and we are addressing that gap through staff additions.

- **Systems Engineering** – for this function, we are proposing to add 24 engineers. Workload levels for this group have increased over the last three years, for two reasons. The first reason is simply to be responsive to plant needs. The second is to be responsive to industry expectations to implement standards of excellence - INPO AP 913 and INPO AP 928 - regarding equipment performance, trending and overall reliability. The standard of excellence in performance previous to 2012 had been with primarily safety-related systems. As enhanced plant risk assessments (PRA) and implementing NRC Regulatory Guide 1.200 were performed, other potential vulnerabilities to safety were identified in non-safety related systems, many of them balance-of-plant systems (other than the reactor itself). That meant the performance of non-safety related systems that had significant worth to reactor core damage frequency protection must be monitored for health, analyzed for trend, and monitored for reliability maintenance to mitigate vulnerabilities to overall plant safety.

  The NRC's NRC Reactor Oversight Process (ROP) specifically identifies that transient initiators to reactor operations are the highest source of generating plant events challenging the reactor core. Transient initiators are predominantly from non-safety related systems and components. This regulatory safety focus on the production side (balance-of-plant) of the power plant required additional engineering oversight and management to prevent transient initiator challenges to the overall plant operations. This takes the form of system walk-downs, preventative maintenance reviews and programs, operating trends analysis, and long range life cycle management decisions. Additionally, increased focus on corrective action determinations from day to day operations, maintenance work performed and the searching of industry operating experience and best practices for inclusion in system health reports to these applicable systems.

- **Probabilistic Risk Assessment** – we are adding 10 engineers to PRA to bring an externally sourced function in-house. In 2012, we were relying on a contract firm to perform regulatory required probabilistic risk assessments (PRA) for daily operations (including equipment / systems in service, equipment failures, degraded components while operating , fire protection analysis / alterations, and plant modification changes being made) to validate that overall plant safety is moving to an improved position. The contract firm went bankrupt in 2013, and the cost of other suppliers available was too expensive. So we hired 10 of our own personnel to perform PRA work.

Our increase in engineering staffing has already produced favorable results. The following summarizes the impact and performance improvements to date as a result of the staffing increases discussed previously:

Design & Systems Engineering - The additional staffing in these areas has displaced some contracted resources and has the added benefit of improving internal knowledge retention. We believe additional staffing has also impacted plant equipment performance, as measured by equipment reliability. Our performance has moved from an industry equipment reliability index (ERI) of 75 to an index of 85 over the past two years. This is top quartile industry performance, and supports higher plant reliability which is what we have experienced at Prairie Island in recent years. Improved plant reliability at Prairie Island is demonstrated in several ways: through the reduction in forced or unplanned shut downs since 2011, through extended continuous run times (480 days for Unit 2 and 460 days for Unit 1), and through an increase in available capacity factor (94 percent for Unit 2 in 2012-2013, and 98 percent for Unit 1 in 2013-2014. Finally, the Prairie Island plant is at top-decile industry performance as measured by unplanned transients or trips, proving superior performance and value to customers with these added people.

PRA Staffing - Since the original design of the PI plant, it had had over 40 years of operation/modifications and regulatory expectation changes over time, with safety system requirements (the NRC's Mitigating Systems Performance Index) indicating risk values for the plant which revealed PI was at a higher than desirable risk in core damage frequency. This in-house risk assessment team not only performs daily assessments of the plant operating safety (consistent with regulatory requirements) but has prioritized maintenance work, as well as modifications, providing more effective methods and solutions to improve the safety of the plant long term. As a result of adding staff, plant risk -- as measured by core damage frequency -- has improved by an order of magnitude (from 10^{-4} to 10^{-5}), which complies with the NRC safety goals. As an example, one plant project which is in the test year rate case (Reactor Coolant Pump seals upgrade) effectively planned one modification to address two NRC safety initiatives: (1) core damage *margin* improvements with day-to-day operations and, (2) core damage *frequency* improvements for the new post-Fukushima regulatory expectations. Finally, from a cost perspective, we estimate that by adding in-house resources to this group, Nuclear has saved over $1.5 million in costs over the last 3 years when compared to contracting that work externally.

B. This question is addressed in detail on pages 3-5 of Attachment A to this response, which was also provided in response to XLI-120 as Attachment A in this proceeding.

In Fleet/Corporate Oversight functions, 16 of the 30 positions added to headcount are due to new positions added for 2013 and 2014. These oversight positions are not supervisors in the sense of overseeing individual employees. Rather, they are part of our governance and oversight process for our fleet of nuclear generating plants. These new positions were primarily in the following groups:

- Emergency Preparedness
- Performance Improvement
- Outage
- Regulatory Services / Licensing
- Standards / Procedures / Controls
- Nuclear Oversight / Quality Assurance

Nuclear's strategy in adding these new positions was to improve fleet/corporate oversight of plant operations. Regulatory and industry expectations have evolved to a point where these oversight functions need to be more involved in monitoring and challenging plant performance and decision-making. The benefits expected as a result of the staffing initiatives in Fleet/Corporate Oversight are:

Northern States Power Company

- *Emergency Preparedness* – support oversight of compliance with NRC's Emergency Plan 30-minute response requirements. The NRC has issued new rules requiring ERO minimum-staffing to meet a 30-minute response level.

- *Performance Improvement* – Added oversight roles to lead (1) performance improvements at the Company's two nuclear operating plants resolving and closing a backlog of identified problems with cost-effective, timely solutions that comply with regulatory requirements; and (2) a look forward to industry technology and regulatory changes to help effectively position the Company to implement and adapt to future regulatory requirements. An added benefit to these positions is they provide the required bench strength in-house to succeed into key leadership positions at the plants when those individuals move to other positions or retire.

- *Outage* – To improve efficiency and reduce costs, outages must be performed safely, predictably, and while meeting plant reliability and regulatory requirements. We are investing in additional headcount to bring in experienced leadership to improve our governing standards and oversight for outage preparation and execution. These increases are expected to improve outage execution and plant safety and reliability, while reducing overall outage cost.

- *Regulatory Services/Licensing* –Additions to the regulatory organization provide resources to regain and retain regulatory margin by improving proactive engagement with the regulator and ensuring compliance is maintained at or above baseline levels of performance. The benefit of these strategies is more effective use of all resources on self-directed initiatives as contrasted with continued regulatory response needed to address externally identified compliance issues.

- *Standards/Procedures/Controls* – A governing standards organization has now been created to (1) ensure that proper documentation of Nuclear's management model and implementing procedures exists, to provide the proper standards of conduct and performance, and (2) ensure that such documentation is properly compiled, organized, and adheres to industry standards. The administrative workload associated with this effort is most efficiently handled by a centralized service organization, which allows more experienced managers to function in their oversight capacities across the fleet.

Docket No. E002/CI-13-754

Northern States Power Company

- *Nuclear Oversight/Quality Assurance* – Recent industry benchmarking and increased demands for more thorough oversight have identified the need to increase the resources applied to Nuclear Oversight / Assessment activities. A rotational position was created within the group to be staffed from a line organization to meet this need.

Witness:	Timothy J. O'Connor
Preparer:	Nathan L. Haskell / Scott L. Weatherby
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Date:	April 8, 2014

INITIATIVE #1 – Staffing

Mr. O'Connor's Testimony included the following information on staffing increases included in the 2014 test year:

- Table 10 (page 88) identified a $13.0 million cost increase related to adding 156 positions in Nuclear from December 2012 through the 2014 test year.
- Table 11 (page 89) showed the expected timing of the addition of 156 positions from 2012 to 2014, by Nuclear site/location.
- Chart 1 (page 94) showed the functional breakdown of the 156 additional positions being added to Nuclear from 2012 to 2014.

In summary, Nuclear headcount is projected to change as follows from Dec. 31, 2012 to the 2014 test year budget:

	Monticello	Prairie Island	Fleet Oversight	Total Nuclear
Positions filled Dec. 31, 2012	501	662	116	1,279
Budgeted positions not filled 12/31/12	26	13	16	55
New positions added in 2013 & 2014	4	75	22	101
Budgeted positions for 2014	531	750	154	1,435

The level of total vacant/unfilled positions as of 12/31/12 was about 4.1% of budgeted headcount. This compares to Nuclear's budgeted attrition/vacancy assumption for 2014 of 2%. We expect this level of improvement (or better) due to our ongoing staffing initiatives and concerted efforts toward hiring and retention. To the extent that budgeted positions were/are vacant in 2012-2014, the budgeted labor costs were/would be redeployed to contract resources to enable us to perform our work.

The following table describes the other benefits expected from the added headcount in 2014, in comparison to actual positions filled at Dec. 31, 2012, by functional area.

Table 1: Nuclear Staffing Initiative

Staffing Area	Headcount Increase – Dec 2012 to 2014	Benefits Expected
Engineering	41	In Engineering, 31 of the 41 positions added to headcount since December 31, 2012 are due to new positions added in 2013 and 2014. These new positions were primarily in Prairie Island's site engineering group and in the Fleet engineering group. Nuclear's strategy in adding these new positions was twofold: to respond to increasing regulatory requirements in this area, and to build more in-house engineering competencies and reduce reliance on higher cost contract engineering resources. The positions added to date have already begun to improve the technical rigor and product output of our engineering work at both plants. For example, we were able to implement several key configuration changes that improved the safety margins at the plants. We were also able to make a very challenging change to better position the plants to withstand a Fukushima-type external event. This was a complex modification that was implemented in a timely manner with the support of the increased staffing. In addition, increased staffing at Prairie Island has allowed the station to address equipment obsolescence issues, critical backlog reductions, and equipment reliability concerns. The Emergency Diesel Generator Safety System performance is another example where engineering resources were applied to reduce challenges, improve reliability and improve safety margins. These recent performance changes have been acknowledged and noted in the recent INPO Evaluation as well by outside regulators (NRC).

Staffing Area	Headcount Increase – Dec 2012 to 2014	Benefits Expected
Engineering (continued)		The long-term benefits of increased staffing in Engineering include (a) raising the overall engineering performance levels beyond regulatory compliance, and (b) becoming more proactive at detecting issues before they require significant corrective actions. Also, additional resources will help support reductions in backlogs of Correction Action Program (CAP) issues, and in Engineering Change (EC) analysis required to support plant modifications. These backlog reductions allow improved response time to other station challenges as they arise.
Fleet/Corporate Oversight	30	In Fleet/Corporate Oversight functions, 16 of the 30 positions added to headcount are due to new positions added for 2013 and 2014. These new positions were primarily in the following groups: • Emergency Preparedness • Performance Improvement • Outage • Regulatory Services / Licensing • Standards / Procedures / Controls • Nuclear Oversight / Quality Assurance Nuclear's strategy in adding these new positions was to improve fleet/corporate oversight of plant operations. Regulatory and industry expectations have evolved to a point where these oversight functions need to be more involved in monitoring and challenging plant performance and decision-making. The benefits expected as a result of the staffing initiatives in Fleet/Corporate Oversight are: • Emergency Preparedness – support oversight of compliance with NRC's Emergency Plan 30-minute response requirements. The NRC has issued new rules requiring ERO minimum-staffing to meet a 30-minute response level.

Staffing Area	Headcount Increase – Dec 2012 to 2014	Benefits Expected
Fleet/Corporate Oversight (continued)		• Performance Improvement – Added oversight roles to lead (1) performance improvements at the Company's two nuclear operating plants resolving and closing a backlog of identified problems with cost-effective, timely solutions that comply with regulatory requirements; and (2) a look forward to industry technology and regulatory changes to help effectively position the Company to implement and adapt to future regulatory requirements. An added benefit to these positions is they provide the required bench strength in-house to succeed into key leadership positions at the plants when those individuals move to other positions or retire. • Outage – To improve efficiency and reduce costs, outages must be performed safely, predictably, and while meeting plant reliability and regulatory requirements. We are investing in additional headcount to bring in experienced leadership to improve our governing standards and oversight for outage preparation and execution. These increases are expected to improve outage execution and plant safety and reliability, while reducing overall outage cost. • Regulatory Services/Licensing –Additions to the regulatory organization provide resources to regain and retain regulatory margin by improving proactive engagement with the regulator and ensuring compliance is maintained at or above baseline levels of performance. The benefit of these strategies is more effective use of all resources on self-directed initiatives as contrasted with continued regulatory response needed to address externally identified compliance issues.

Staffing Area	Headcount Increase – Dec 2012 to 2014	Benefits Expected
Fleet/Corporate Oversight (continued)		• Standards/Procedures/Controls – A governing standards organization has now been created to (1) ensure that proper documentation of Nuclear's management model and implementing procedures exists, to provide the proper standards of conduct and performance, and (2) ensure that such documentation is properly compiled, organized, and adheres to industry standards. The administrative workload associated with this effort is most efficiently handled by a centralized service organization, which allows more experienced managers to function in their oversight capacities across the fleet. • Nuclear Oversight/Quality Assurance – Recent industry benchmarking and increased demands for more thorough oversight have identified the need to increase the resources applied to Nuclear Oversight / Assessment activities. A rotational position was created within the group to be staffed from a line organization to meet this need.
Operations	27	In Operations, 16 of 27 positions added to headcount were new positions added at Prairie Island to meet regulatory requirements for Emergency Planning and to assist in improving operational performance towards top-quartile. Staffing increases are required to support the expected levels of retiring licensed operators at Prairie Island. Also, the NRC has issued new rule requiring ERO minimum-staffing to meet a 30-minute response level. Recent industry benchmarking indicates that our level of Operations staffing is lower than the median of other nuclear units in the U.S.

Northern States Power Company

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Staffing Area	Headcount Increase – Dec 2012 to 2014	Benefits Expected
Maintenance	19	In Maintenance, all of the positions added to headcount are due to new positions added for 2013 and 2014 across both plant sites. Addressing equipment issues in a timely manner increases the margins of safety and improves output capability. These staffing increases are necessary to allow the Maintenance department to effectively and timely address equipment deficiencies arising and reduce existing backlogs of issues previously identified. Both plants are challenged by equipment deficiency backlogs which if not addressed will result in increased regulatory scrutiny. The regulatory position on equipment deficiencies that result in transient initiators has changed. For example, the NRC recently raised regulatory concerns for another nuclear utility that experienced transient/degraded conditions related to equipment deficiencies, which resulted in increased oversight/inspections and related costs. The additional maintenance resources added to the Prairie Island Station have already started to render positive results. The maintenance deficiencies at that plant have started to decrease, and equipment reliability and station output capacity have improved. These improvements have been recognized by outside stakeholders (INPO) and regulators (NRC). In addition, recent industry benchmarking indicates that our level of Maintenance staffing is lower than the median of other nuclear units of the same design and size.

Staffing Area	Headcount Increase – Dec 2012 to 2014	Benefits Expected
Radiological Protection	10	In Radiological Protection, 4 of the 10 positions added to headcount are due to new positions added for 2013 and 2014 at Prairie Island. This level of staffing in Radiological Protection is required to meet regulatory requirements for Emergency Plan staffing. The NRC has issued new rule requiring ERO minimum-staffing to meet a 30-minute response level. Recent industry benchmarking indicates that Prairie Island's level of Radiological Protection staffing is lower than the median of other nuclear units in the U.S.
Training	9	In Training, 8 of the 9 positions added to headcount are due to new positions added in 2013 and 2014. These new positions were added at both plant sites, but primarily at Prairie Island. This level of staffing in Training is needed to meet regulatory requirements for training of operational staff. Due to the level of new hires in Nuclear, and recent attrition of existing staff (mainly at Prairie Island), the resources required to train new operators and keep staff compliant with training curriculum have increased. Nuclear's strategy in adding these new positions is to build in-house training resources and avoid the alternative of contracting the training activities to outside firms at a higher cost.

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Staffing Area	Headcount Increase – Dec 2012 to 2014	Benefits Expected
Project Management	6	In site Project Management, 2 of the 6 positions added to headcount are due to new positions added in 2013 and 2014. New positions were added only to Prairie Island's projects group, and the net increase reflects reductions at Monticello due to lower capital support required after the completion of the LCM/EPU project in 2013. Vacant positions in this area during 2012 and 2013 were resourced through outside contractors. Nuclear's strategy in adding these new positions at Prairie Island is to strengthen in-house project management resources and lessen reliance on the use of higher-cost contract resources. This will also improve our project cost estimating and management activities. While the large LCM/EPU project at Monticello and the steam generator project at Prairie Island are now complete, ongoing project management activities will be essential to support the continued safe operations over the 20-year operating license periods at both plant sites.
Chemistry	4	All of the headcount increase in Chemistry is due to filling vacancies existing at both plant sites. This level of staffing in Chemistry is necessary to meet operating and regulatory compliance expectations. Recent industry benchmarking indicates that our level of Chemistry staffing is lower than other nuclear units in the U.S.
Other	10	In Other functions, 6 of the 10 positions added to headcount are due to new positions added in 2013 and 2014, mainly at Prairie Island and Fleet headquarters. These Other functions include Security, Supply Chain/Procurement, Procedures & Document Controls, Records Management, Licensing, and Administrative Services. The level of staffing budgeted in those areas is that necessary to provide business support to plant operations and meet regulatory compliance expectations.
Total Positions Added in 2014 vs. Dec. 31, 2012 actual levels	**156**	

INITIATIVE #2 – Performance Excellence

The 2014 test year non-outage O&M expense for Nuclear included $7.9 million for performance excellence program initiatives, in addition to staffing initiatives supporting performance excellence (which are included in Initiative #1). The following table lists the costs of the various program areas, and describes the benefits expected, from these initiatives.

At the outset, we note that as it pertains to the "Compensation Programs" in the table below, Mr. O'Connor's testimony, in Table 10, shows an "Other" Category of non-outage O&M labor costs. The "Other" category is noted to include "retention, signing, performance bonuses, etc." The $1.7 million in "Other" labor costs represent incremental changes in 2012 actuals to 2014 budget, which includes both the performance excellence initiative as well as other compensation related expenses. We note this because for this answer we have focused on the impact from the performance improvement initiative costs.

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Table 2: Nuclear Performance Excellence Initiative

Performance Excellence Initiative Area	2014 Test Year Cost ($ 1000s)	Benefits Expected
Compensation Programs:		
Sign-on bonuses	$ 805	Sign-On Bonus Programs are an effective tool to help attract and retain employees that are uniquely qualified to work in our nuclear plants in a very competitive talent market. Nuclear is unique and a complex industry. Xcel Energy Nuclear competes with other nuclear operators for hard-to-source and fill positions like engineering supervisors and support for critical nuclear projects, such as refueling outages and large equipment replacements. The nuclear industry labor market is experiencing a significant constraint in the supply of qualified and skilled employees knowledgeable in the nuclear utility industry and the associated regulatory requirements. A variety of factors are affecting the nuclear workforce, including aging, and a lack of entry-level candidates also exists due to low graduation rates from nuclear programs. There is an increased demand for qualified resources due to increased regulation and oversight requirements. All of our sign-on bonuses include a retention clause requiring a payback of bonus dollars if the new employee leaves the Company within the first 2 years of employment.
Market pay adjustments	854	Market pay adjustments are used throughout the industry to help keep salaries within an acceptable range to attract and retain employees. Xcel Energy has made, and expects to continue to make, base pay adjustments to a number of jobs and individuals, based on the critical nature of their role and the talent of the employees to ensure we can continue to successfully operate by remaining competitive within our comparable salary markets. See explanation in "Benefit Expected explanation for Sign-on Bonuses" item for further description of the marketplace for Nuclear talent.
Retention program	695	Retention programs are compensation tools to help attract and retain employees that are qualified to work in our nuclear plants. See explanation in "Benefit Expected explanation for Sign-on Bonuses" item for further description of the marketplace for Nuclear talent.
Subtotal – 2014 Cost for Compensation Programs	**$ 2,354**	

Performance Excellence Initiative Area	2014 Test Year Cost ($ 1000s)	Benefits Expected
Prairie Island Performance Improvement:		
High priority repairs - fire impairment	1,176	The number of fire impairment risks is being reduced to return Prairie Island to regulatory compliance, consistent with industry standards. Implementation of this scope of work will: • Return selected physical fire mitigation systems and equipment to fully functional status ensuring the safety of both plant equipment and personnel in the event of a fire • Align the selected fire protection features with the plant's design basis. • Eliminate a set of fire watches currently in place at Prairie Island
Procedure change request backlog reduction	1,200	Nuclear regulations require plant operation and maintenance processes be continually refined, updated, and documented. Equipment and systems can be upgraded and changed. Technical issues can require new processes to be followed, and in some cases, "work-around" solutions are needed until equipment upgrades or implementations occur to permanently address issues noted. In all of these circumstances, the changed procedures must be tracked and documented procedures must be updated. A backlog of procedure change requests pending is maintained, and has built up over time. The planned backlog reduction effort will provide resources to assist current site staff with implementation of long-standing procedure change requests, ensuring that procedures being used in the field are current and have the most up-to-date information. This will provide better site ownership of procedure use and enable better adherence to expectations for backlog progression.

Performance Excellence Initiative Area	2014 Test Year Cost ($ 1000s)	Benefits Expected
Legacy engineering change closeout	789	The purpose of this item is to take the necessary actions to complete and close out an identified list of open Engineering Changes (ECs) required under NRC regulation 10CFR 50.59. Engineering tasks to be performed include Safety Evaluation screenings, calculations, drawings, specifications, and program updates. Implementation of this scope of work will align station configuration control documents with the current physical configuration of the plant.
Operations burden backlog	554	The plant maintains a backlog list of open "operations burden" items, to address specific degraded and nonconforming conditions at the plant. This project will perform the work required to remove a number of specific degraded and nonconforming conditions from the plant. In the process, configuration management is being re-established between the physical plant and corresponding design documentation. Specific work scope planned includes repairs to doors, pipe hangers, and the reactor protection train, and other changes in physical plant configuration.
Emergency Diesel Generator (EDG) #5 & #6 Procurement engineer + painting	300	The focus of the diesel reliability project was to identify equivalent replacement parts on Unit 2 (U2) EDGs due to obsolescence. A number of components on the U2 EDGs are obsolete and no longer supported by the original equipment manufacturer (OEM). This project will support long-term operation of U2 EDGs and availability of spare subcomponents (in conjunction with the OEM and other nuclear sites). Also, painting the EDGs is required maintenance to support preservation of the equipment over its life.
Performance Improvement Team	1,078	Staffing of the Prairie Island Improvement Team will be a combination of employees (who are being temporarily removed from the general plant positions) and short-term contractors (where the plant is unable to support this initiative solely with internal staffing). The positions vacated by plant employees are being backfilled, requiring the need to fund these backfilled positions until the improvement initiative is complete.

Performance Excellence Initiative Area	2014 Test Year Cost ($ 1000s)	Benefits Expected
Other Fleet/Corporate Oversight Performance Improvement:		
Additional Nuclear oversight meetings and resources	215	Non-labor resource requirements are being increased for both oversight committee meetings and oversight contract staff. • Due to the improvement efforts ongoing at the site, the Chief Nuclear Officer has increased the number of Management Safety Review Committee (MSRC) meetings for 2013 and 2014. These additional meetings will allow for independent resources to provide feedback on Nuclear's current performance and to assist Nuclear with making progress toward meeting the initiative's goals. • Nuclear Oversight resources were also increased to add contracted technical specialists for quality assessments of line organization performance to support assessment of progress towards top quartile / industry standards.
DevonWay software and services – governance and oversight support	186	Nuclear is planning to upgrade/replace the current software used to manage and monitor corrective action programs (CAP). NRC regulations require a disciplined and effective corrective action program, where compliance and performance gaps are managed, monitored and ultimately corrected. The current software in use for CAP has become obsolete and limiting for our needs as it was designed based on regulations from approximately 30 years ago. This initiative will replace the obsolete technology with a cloud-based solution that provides intuitive functioning, reliability, scalability, cost-effectiveness, and agility. Such a solution is consistent with recent implementation practices in the U.S. Nuclear industry.
Subtotal – 2014 Cost for Performance Improvement Programs (excluding compensation)	**$ 5,498**	

Performance Excellence Initiative Area	2014 Test Year Cost ($ 1000s)	Benefits Expected
Total 2014 Cost of Performance Excellence Initiative (excluding Staffing Items also included in Initiative #1)	**$ 7,852**	

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Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	108
Requestor:	Chris Shaw, Nancy Campbell		
Date Received:	April 25, 2014		

Question:

Are there other personnel who are available to supplement Monticello site personnel in the event of an extraordinary project need with extra heavy workload requiring additional human resources? In other words, can Xcel call on its own in-house personnel to help with a project or projects that demand more full time equivalents than are available at the Monticello plant site?

Response:

Yes. Our response to DOC Information Request No. 107 provides a summary of the Company's personnel who are available for (i) both operations and maintenance and routine projects, (ii) major capital projects such as the LCM/EPU Program, and (iii) when it is necessary and appropriate to engage contractors and consultants to supplement our employee workforce.

The Company has available to it both internal and external personnel who are available to supplement the workforce when necessary to meet the demands of particular projects. We continually evaluate staffing and labor needs under the given circumstances and assess whether it is more cost-effective to use full time employees or contract labor for various work. The decision will vary based on time constraints, expertise, and similar factors. This is standard practice in the nuclear industry, particularly when it comes to staffing for major capital projects.

The Company routinely calls on its own in-house personnel and contract experts to help with a project or projects that demand more full-time equivalents than are normally available at the plant sites. In some circumstances, such as developing and implementing major capital projects, contractors can be a more cost-effective resource. Contractors can be brought in for the duration of a project and can be easily eliminated once the contractor's work is done. It would be highly inefficient to staff with internal employees for the work needed to deploy major projects as those employees would then not be utilized once the project was completed and would either need to be laid off or underutilized. Further, at times contractors may have more targeted expertise for particular project-related tasks and it is more efficient to access that expertise than to try to develop it in-house.

Ultimately, the Company has the responsibility to ensure that work done is appropriate and meets all applicable requirements, whether or not that work is deployed by employees or contractors. As a result, the Company takes a hands-on approach to overseeing the work of employees and contractors at the Site. The Company's procedures ensure that the Site maintains overall design authority over the work that is being proposed (whether that work is routine or arises from a major capital project). The Director of Engineering at the Site is an employee of the Company and oversees the overall design of and quality of the work undertaken by employees and contractors alike.

Additionally, the Sites use a variety of methods to supplement personnel on specific projects to aid in the timely completion of a particular work package. One key example of where we deployed additional support to the LCM/EPU Project was that equipment experts were contracted to provide oversight of the pump vendors during both the fabrication and factory acceptance testing phases of construction. They were deployed to the vendors to facilities to oversee these functions. This was critical for several reasons. First, the station lacked the specific expertise to resolve some technical equipment issues. Second, questions and conflicts were resolved on the spot. This ensured the equipment delivery dates did not slip, which would have jeopardized the outage schedule. These same individuals supported start-up testing and helped resolve numerous equipment related issues through all phases of power ascension. Their specific expertise in Feedwater Tuning and electrical testing helped the plant avoid transits that could have resulted in bringing the unit off-line.

Preparer: Mark Schimmel
Title: Vice President, Nuclear
Department: Nuclear
Telephone: 612-215-4613
Date: May 7, 2014

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☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	77
Requestor:	Nancy Campbell/Chris Shaw		
Date Received:	April 16, 2014		

Question:

Please provide the following information regarding an NSP Document titled "EPU Cost History" (provided in Xcel's response to DOC information request no. 50; the document has a filing reference number NSP 0044875 – NSP 0044879):

a. Author,
b. Docket or Case in which it was presented as an Exhibit or supporting information,
c. Date of the document,
d. Purpose of the document,
e. Whether this document was submitted as an Exhibit to an NSP Witness Testimony,
f. If the answer to (e) is affirmative, please identify the name of the Witness,
g. Please indicate whether this information is still timely or whether any data (costs, schedules, projects, etc.) has expired, been deleted, replaced, amended or changed in any way.
h. Please provide details documenting any changes defined in Item g. above.

Response:

a. Steven J. Hammer

b. None

c. October 2011

d. During the timeframe when this document was created (October 2011), the LCM/EPU Program management structure was evolving. The Vice President of Nuclear Projects had recently retired and the Company was in the process of replacing the Program Manager position for the LCM/EPU Program. As a result, the Chief

Nuclear Officer at the time (Dennis Koehl) was seeking input on the Project structure and opinions on the best way to proceed forward to complete the installations. Mr. Koehl was also concerned about the overall Project costs as we moved out of the 2011 outage. Mr. Hammer is a long-time employee in the Nuclear Department and was a member of the LCM/EPU Program team throughout. Thus, Mr. Koehl requested that Mr. Hammer provide background and his personal perspective as to why the Project was in excess of the most recent forecast. .

Response to IR DOC-78 provides more information regarding the context for some of the concerns raised in the memo.

e. No.

f. N/A

g. The data used by Mr. Hammer in preparing the memo was based on documents available to him at the time, including the Company's internal cost accounting database, and on his knowledge of the Program based on his participation as a member of the internal project team. The information Mr. Hammer was using correlate to our budget to actual and our budget to budget information and constituted cost data that was current as of the Fall of 2011. For example, the installed cost numbers in the chart referenced on page 3 of 5 in the memo appear to reflect the accounting system costs as of the timeframe of the memo. All of these numbers have all been supplanted by the data provided in the current filing, including Schedule 7 to Mr. O'Connor's direct testimony and the cost database provided with Mr. Weatherby's direct testimony.

h. *See* Response g.

Preparer:	Mark Schimmel
Title:	Vice President, Nuclear
Department:	Nuclear
Telephone:	612-215-4613
Date:	April 28, 2014

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Xcel Energy
Docket No.: E002/CI-13-754
Response To: Department of Commerce Information Request No. 78
Requestor: Nancy Campbell/Chris Shaw
Date Received: April 16, 2014

Question:

In the above-referenced document, NSP, ultimately Xcel, identifies numerous management decisions involved with the cost over runs. Please provide a discussion of the decisions made, approvals and reasoning for deviating from the proposed estimate and an estimate of the specific cost impact by these issues:

a. In the year 2006, the Xcel Board of Directors approved a budget of $273M in difference to the Site Projects Group recommended budget of $362.5M;
   i. By item, what were the bases for reducing the budget recommended by the Site Projects Group?

b. In the year 2008, the costs were $9.6M over the predicted value for the year. The Financial Council approved a $49.4M budget increase above the 2006 approved budget of $273M, while the scope of work eliminated fuel pool heat exchangers, summer derates, SJAE Valve upgrades, circulating water and cooling tower upgrades, under vessel cables.
   i. What were the causes of the $9.6M cost overrun?
   ii. What was the basis for the $49.4M budget increase?
   iii. What were the values of each of the components eliminated from the overall project?

c. In the year 2009, please explain why CARV replacement was more complicated than anticipated. Did the Sites Projects Group recognize the possibility of this complication? Please explain if this is why their 2006 budget was higher than the Board approved?

d. In the year 2009, the total projected cost increase was $39.4M. Xcel states that "most of the increase was due to 2009 expenditures being $28M above predicted."
   i. What were the causes of the $28M cost overrun in 2009?

   ii. What were the causes of the additional $11.4M differential above the $28M amount?

e. In the year 2010, costs were $6.2M above predicted but could not be identified. What was the basis for this $6.2M increase and why could it not be identified?

f. Please explain why the Board over ruled the Project Team's recommendation for installation during the 2011 and 2013 refueling outages instead forcing a complicated issue into one outage, 2011?

g. Please explain why the Board and Senior Management did not base its decisions more closely on the Project Team's recommendations throughout the LCM/EPU project.

h. Please explain the statement "the site did not have cost of ownership of the budget." In addition, please explain why the site did not have cost ownership of the budget.

i. Please explain the statement: "Site Steering Committee review meetings resulted in significant scope being added."
   i. Please provide an itemized list of the additions to the scope over time, including the amounts attributed to each year.
   ii. Was a Project Manager responsible to Senior NSP Management for the overall scope? If so, please identify the Project Manager(s). If not, please explain why not.

<u>Response</u>:

The initial part of this question states that "Xcel identifies numerous management decisions involved with cost overruns." The memo actually provides Mr. Hammer's view of these issues. Xcel Energy senior management, including Mr. O' Connor, provides the Company's view of the reasons for the cost increases. Mr. O'Connor does not view many of the concerns raised as primary contributors to cost increases, and to the extent that they did have some impact, it is difficult to quantify, or to be certain that an alternative decision would have led to a lower cost Project. Mr. O'Connor does believe that changes to the scope of the Program increased the overall costs but that these changes were both necessary and appropriate for continued safe operation of the plant.

Question:

a. In the year 2006, the Xcel Board of Directors approved a budget of $273M in difference to the Site Projects Group recommended budget of $362.5M;
    i. By item, what were the bases for reducing the budget recommended by the Site Projects Group?

Response:

The Board of Directors did not reduce the budget recommended by the Site Projects Group. Rather, the initial Nuclear Project Authorization (NPA) set an initial high-level estimate of $273 million ($2006$) for the initiative. As stated in response to DOC IR-77, document NSP-0044785-789 was prepared in 2011 (several years after the initial NPA) by Mr. Hammer at the request of the then-Chief Nuclear Officer, Dennis Koehl, as a history and opinions on why the Project was exceeding its forecast and the appropriate structure in light of key personnel changes. That document represents that one employee's opinions about the history of the LCM/EPU Project as of that date that he prepared the document. The $362.5 million figure was the high-end of a range of $299-362.5 that was also developed by Mr. Hammer in 2006 for the Chief Nuclear Officer's consideration. The number represented the high end of a wide range of cost estimates that had been developed. Project leadership at the time brought forward the request for the $273 million based on the review of the entire situation, including the proposal we had received from General Electric. The capital Project was ultimately approved by the Financial Council and the Board at the $273 million level that the Project team had recommended.

The $273 million ($2006$) in the initial NPA was based primarily upon a cost assessment prepared during the 2006 Cost Scoping Assessment conducted by General Electric at Xcel Energy's request. That assessment identified the types of activities that we expected would need to be undertaken to achieve the fundamental corporate goals of (i) undertaking LCM subprojects necessary to enhance the operation of the plant throughout its extended operating license, and (ii) increase the capacity of the plant by between 69 and 73 MWe. The cost assessment was based upon General Electric's experience, as well as the Company's knowledge of the types of upgrades that would be necessary to support both the LCM and EPU goals of the initiative. The estimate prepared by plant personnel identified in the memo was requested by management in the 2006/2007 timeframe and was specifically requested as a high-end estimate to provide additional context to inform management's decision about the initial estimate to use in the NPA. The $362 million estimate included additional contingencies and described additional potential work that could be considered. At the same time, plant personnel provided a low-end estimate of $299 million to provide a range for management's consideration. A spreadsheet showing how the $299-362 million range was prepared has been produced as document NSP-0000031-53.

Recognizing that the Cost Scoping Assessment supporting the initial NPA was preliminary, the Project team determined to request funding at the lower level as there was not substantial cost support for either estimate, given the high level nature of the estimate. Mr. Hammer's opinions were discussed and Project management decided to proceed on the basis of the Cost Scoping Assessment. In addition, senior management elected to treat the initiative as a single large project rather than to pursue multiple independent modifications.

We note that we did provide a high end sensitivity on the $273 million in the alternatives analysis conducted during the Certificate of Need proceeding at roughly $346 million, which while not precisely the same as the high-end assumption of $362 million, provided the Commission similar context for the range of potential outcomes that were being discussed at the time of the decision to move forward with the Project.

Question:

b. In the year 2008, the costs were $9.6M over the predicted value for the year. The Financial Council approved a $49.4M budget increase above the 2006 approved budget of $273M, while the scope of work eliminated fuel pool heat exchangers, summer derates, SJAE Valve upgrades, circulating water and cooling tower upgrades, under vessel cables.
    i. What were the causes of the $9.6M cost overrun?
    ii. What was the basis for the $49.4M budget increase?
    iii. What were the values of each of the components eliminated from the overall project?

Response:

i. The explanation for the $9.6M cost increase over predicted value for 2008 is explained in document NSP-0044785-789 on page 1 of 5. Mr. Hammer correctly points to a number of subprojects that were being analyzed in the 2008 timeframe. While the costs were not tracked by specific modification or activity at that time, the 2008 cost increase was related to the work that was done at that time. The costs incurred during this timeframe is also described in Mr. O'Connor's direct testimony regarding the costs of the condensate demineralizer modification (pp. 39, 79, 105-08), the work on assessing whether to include a new steam dryer (pp. 53, 102-05) and other items described in the memo. As explained in the memo, the discussion of this amount represents the memo author's interpretation of the data that was available to him. As noted on pages 105-107 of Mr. O'Connor's direct testimony, the Company's initial proposal was to replace only portions of the condensate demineralizer system. In 2007, the Company concluded that it was in the plant's interest to replace this entire aging system. In 2008, the Company began developing this subproject for implementation. Some of these costs were additional and some were related to timing. In addition, deviations included costs associated with preparation of the NRC license resubmittal.

ii. As stated in the memo, the basis for the $49.4M increase from the original $273M NPA was based primarily on the addition of the steam dryer to the scope of work in 2008 as well as further refinement in our analysis of necessary upgrades to the plant's electric distribution system. The steam dryer replacement (estimated cost $28M) was ultimately supported by a separate NPA, the 13.8 kV modifications, which were ultimately supported by a separate NPA, and the increased spending in 2008 ($9.6M) makeup the increased authorization of $49.4M.

iii. This subpart requests the value of the components eliminated from the initial NPA scope. The five subprojects that were identified in the question were: (i) fuel pool heat exchangers, (ii) summer derates, (iii) SJAE Valve upgrades, (iv) circulating water and cooling tower upgrades, and (v) under vessel cables. Just as the condition of equipment was evaluated that led to scope additions (eg. the feedwater heaters), the Project also evaluated items initially thought to be in need of upgrade or that may be beneficial to proceed with as part of the Project and determined that they were not. All of the subprojects were found to be unnecessary at the time and were therefore eliminated from the scope of work. Given the level of uncertainty regarding other cost estimates, the overall budget create for 2009 was not reduced to reflect these decisions.

The specific information requested is provided in the table below:

	Project	Status	Reason	Cost*
(i)	Fuel Pool Heat Exchangers	Cancelled – Not currently considered necessary on technical grounds	In 2007 when the initial NPA was authorized we were concerned that these heat exchangers would need to be replaced. Heat exchangers are subject to two phenomena – flow-induced vibration/fretting and corrosion. We conducted a careful review of these heat exchangers and found them to be in good working order. We also determined that EPU would not impact system flow or heat rejection requirements and therefore we did not need to pursue this project. We conducted an eddy current test and determined that the tubes are in good shape and that they were not subject to fretting from flow-induced vibrations. Further, the type of heat exchangers that are used for this function utilize a chromate, closed-loop system that is resistant to corrosion. Our assessment was that these heat exchangers should last for the duration of the extended operating license without need for repair. We are monitoring this component appropriately and will take corrective action if necessary.	$1 million

	Project	Status	Reason	Cost*
(ii)	Summer Derate	Cancelled - not currently being considered based on economic grounds	The Company sponsored a study from Sargent and Lundy that showed that operating at uprate conditions could result in a modest increase in the number of days the plant would need to be derated due to hot weather. That report found that the cost of the project was not justified at the time based on the modest amount of benefit that would be achieved and in light of emerging but not-yet-final new EPA rules. That study analyzed the cost of making immediate improvements to the heat rejection systems compared to the cost of waiting until new EPA regulations were in place. Given the uncertainty about what upgrades might be required by the rule, the Company determined that it was better to deploy that cost on other subprojects designed to meet the overall Project goals at that time.	$8 million

	Project	Status	Reason	Cost*
(iii)	SJAE Valve Upgrade	Cancelled	In 2006/7 when the LCM/EPU Project was first developed, we were concerned that the Steam Jet Air Ejector valves were undersized for us at uprate conditions. Thus this subproject was included in the original NPA. We subsequently conducted a study and determined that the valve size was appropriate and this modification was not necessary. Therefore, the subproject was cancelled.	$0.47 million
(iv)	Circulating Water and Cooling Tower upgrades	Cancelled – subject to potential future consideration as an environmental compliance project	This was part of the Summer Derate subproject (described in item (ii)). It was not necessary if Summer Derate was not being pursued. In addition, we had identified that the EPA's proposed new rule 316.b might require future work on this system While that rule was being discussed in 2006 (when the initial NPA was approved) it did not actually become effective until 2013. We are reviewing that new rule now and may need to propose future work for compliance with it. However, as noted above, it would have been premature to undertake this work earlier until there was more certainty around 316.b requirements.	*See* Summer Derate above

	Project	Status	Reason	Cost*
(v)	Under-Vessel Cable Replacement	Deferred – Issue being monitored and may potentially result in replacement at some point in the future.	Initially we had assumed the cable would need to be replaced for LCM work. Through more detail review, we determined that this cable was still in good repair and did not need replacing at this time. The cable under the reactor vessel is in a very confined space that would result in high radiation dose levels. Since it was not needed in connection with with other LCM/EPU work, and because later in life replacement was feasible, the Company decided that, if the cable did not need replacing, the work should be deferred.	$2.075 million

* Cost based on the May 2008 Long Range Plan data:

Question:

c. In the year 2009, please explain why CARV replacement was more complicated than anticipated. Did the Sites Projects Group recognize the possibility of this complication? Please explain if this is why their 2006 budget was higher than the Board approved?

Response:

We do not agree with the memo to the extent it suggests that the CARV replacement project was a major cost driver. While it was accurate that the costs of the project was increased due to the need to relocate certain piping and supports and to reanalyze the supports, the extra costs were not significant compared to other aspects of the Program. CARV replacement was more complicated than anticipated due to the fact that high radiation levels during plant operation prevented the ability to inspect the as-built system installed configuration prior to the 2009 outage. This was a consequence of the decision to move forward on parallel paths to make resources available to our customers as soon as possible. Therefore, adjustments to the piping and pipe support design had to be made during installation. We estimate that the costs incurred were in the range of $500,000- $1,000,000 including delays. The LCM/EPU Project team was aware of the risk that differences may exist between station drawings and the actual installed configuration.

Question:

d. In the year 2009, the total projected cost increase was $39.4M. Xcel states that "most of the increase was due to 2009 expenditures being $28M above predicted."
    i. What were the causes of the $28M cost overrun in 2009?
    ii. What were the causes of the additional $11.4M differential above the $28M amount?

Response:

i. Cost increases during 2009 were attributable to the 2009 refueling outage and additional work that was done after the outage in anticipation of the next phases of the work. As described in Mr. O'Connor's direct testimony, pp. 75-78, during the 2009 outage we experienced approximately $9 million of implementation costs over our budgeted amount for the outage. Mr. Hammer's memo describes this as being $10.5 million based upon his interpretation of the budget information he had available to him. Costs incurred during the outages were generally related to the complexity of the work and difficulty installing the modifications.

ii. The majority of the additional costs were attributable to the need for additional labor and materials necessary to complete the work. Table 10 of Mr. O'Connor's direct testimony lists the major modifications that were implemented in 2009. Although costs were not separately tracked by specific modification at that time, the memo accurately reflects that the major activities being undertaken during that year (CARV replacement, Steam Dryer preparation, PRNM, and turbine replacement) all contributed to the overall cost increase experienced that year.

Question:

e. In the year 2010, costs were $6.2M above predicted but could not be identified. What was the basis for this $6.2M increase and why could it not be identified?

Response:

The cost changes were identified as being related to timing differences.

Question:

f. Please explain why the Board over ruled the Project Team's recommendation for installation during the 2011 and 2013 refueling outages instead forcing a complicated issue into one outage, 2011?

Response:

The Board did not overrule the Project team's recommendation. The Nuclear business unit conducted an analysis of the proposed work and the projected benefits. Based on that analysis, the Project team reasonably believed that the work could be accomplished in two consecutive refueling outages in 2009 and 2011. This conclusion was supported by past experience in the industry and was consistent with the scope of work initially identified in the initial NPA. In the environment that the decision regarding timing was made, the Company faced the prospect of much higher natural gas prices than today, and we were also facing pre great recession load growth and capacity need, such that the Project team believed moving forward with the earlier dates was reasonable and likely to be beneficial to our customers. The Project team worked with resource planning and regulatory and recommended this schedule to the Financial Council and the Board.

Question:

g. Please explain why the Board and Senior Management did not base its decisions more closely on the Project Team's recommendations throughout the LCM/EPU project.

Response:

The question presumes that the Project team recommendations were changed by others and we do not agree with the premise. As noted in response to prior questions, the recommendations presented by the Project team were approved. In the Company's corporate structure, major projects are generally developed by the affected business unit for consideration. That business unit is responsible to assess options and provide its recommendations to corporate decision-makers for consideration. To the extent that there are impacts that require input from other areas, such as whether the Project is needed, whether or not there are scope decisions that need to be evaluated or whether there were options on timing that impacted the Project, such as financing or challenges would be brought forward or concerns would be worked through in the course of the decision-making process. The initial LCM/EPU Project budget and scope was not brought forward as an issue to be decided based on options. Rather it was presented as the Project team's estimate of the magnitude of the initiative based on the high-level information known at the time and with acknowledgement that there may be upward changes such as the Steam Dryer. The process of Project team sponsorship for the initiative was followed in this instance. The LCM/EPU Project was developed within the nuclear business unit based upon the input and feedback of many stakeholders within that unit and feedback from Resource Planning and Regulatory. The Project team provided recommendations to senior management and the Board for final decisions.

Question:

h. Please explain the statement "the site did not have cost of ownership of the budget." In addition, please explain why the site did not have cost ownership of the budget.

Response:

Ownership of the budget for the LCM/EPU Project was with the nuclear Project team. The LCM/EPU Program did not report to the Monticello Site Vice President, but rather reported up through the projects organization. Budget and cost accountability was with the LCM/EPU Project Manager who reported to the Vice President Nuclear Projects. Mr. O'Connor's direct testimony at pages 58-70 provides a summary of the project reporting relationship.

The decision was made to manage the project from the Projects Group rather than the site because the Company recognized that the Program was a major initiative that would require dedicated effort and concluded that it was better to manage it as a discrete initiative with separate project management. The 1996 uprate (which was managed by the site) was quite small in scope by comparison. The 1996 effort did not require major construction modifications to the plant and was focused on adjusting calculations and resolving measurement uncertainty. In contrast, the LCM/EPU Program required significant major construction modifications to the plant itself and it was the Company's conclusion that it was better to manage such a major construction initiative with a dedicated project structure. In addition, the Company anticipated using contractors such as General Electric as a major source of work for the initiative. As a result, we concluded that it was more appropriate to manage those contractor relationships through the projects organization rather than by the site. The Company also managed the beginning phases of the Prairie Island LCM/EPU and the Steam

Generator Replacement project through a separate project organization rather than by the plant.

Question:

i. Please explain the statement: "Site Steering Committee review meetings resulted in significant scope being added."
    i. Please provide an itemized list of the additions to the scope over time, including the amounts attributed to each year.
    ii. Was a Project Manager responsible to Senior NSP Management for the overall scope? If so, please identify the Project Manager(s). If not, please explain why not.

Response:

The Site Steering Review Committee was tasked with approval of recommendations for scope changes to the Executive Committee. The Site Steering Review Committee worked with the Project team to assure that changes being proposed or considered by the Project team would be properly designed and that a condition assessment of existing equipment was assessed. For example, the memo cites to some modifications that were added to the Project. Some of these were made in the 2007-08 timeframe as the Project team and the Site reviewed both the long range plans and decided whether or not to bring work forward into the Project. In addition, certain changes were determined to be needed for safe and reliable operations. Others were reviewed and substituted for then-existing scope.

The design and reliability based scope changes for four of the major modifications are discussed in DOC-79. Each of these changes was brought before the Site Steering Review Committee. Major scope changes made at this time included the decision to:

- replace the condensate demineralizer system (this scope change and the yearly costs incurred for that modification is described in O'Connor Schedule 23);
- install two larger reactor feed pumps and motors rather than utilizing a smaller third supplemental pump (this scope change and the yearly costs incurred for that modification is described in O'Connor Schedule 26);
- replace Feedwater Heaters rather than just rerating the existing old heaters (this scope change and the yearly costs incurred for that modification is described in O'Connor Schedule 25);
- install a new 13.8 kV bus and distribution network to support long-term expansion at the plant and to retain the existing 4 kV busses to be dedicated

to support our safety-related systems such as on-site station blackout capabilities, as opposed to adding additional 4 kV busses and breakers (this scope change and the yearly costs incurred for that modification is described in O'Connor Schedule 28);

replace the Steam Dryer rather than rely upon the existing steam dryer with modifications to support our NRC analyses (this scope change and the yearly costs incurred for that modification is described in O'Connor Schedule 22). Other scope changes identified in this portion of the memo (page 4 of 5, item 3.c.) are ones that were not the major changes but rather were additional items that were incorporated into the overall scope of the major modifications. All of the items listed in this paragraph were requested by the Site due to age or condition issues. Specifically, the reasons for these changes were:

- <u>Condensate demin valves</u> – It was necessary to change the controllers on the valves and the existing valve parts were obsolete. Therefore, as part of the overall condensate demineralizer modification it was necessary to replace the valves and controllers. Schedule 7, line 11133705 of Mr. O'Connor's testimony outlines the costs incurred for the overall condensate demineralizer modification.
- <u>Turbine expansion joints</u> – The existing expansion joints were at the end of their useful life and would have needed to be replaced in any event. While work was ongoing on the turbine, the Company determined that the original expansion joints needed to be replaced. It was determined that it made the most sense to undertake this work at the same time as we were replacing the turbine. Schedule 7, line 11132414 of Mr. O'Connor's testimony outlines the costs incurred for this modification. <u>Redundancy for isophase bus cooler</u> – There were cooling limitations on the bus. There was only one cooler and it was operating at the margin. To promote safe and reliable operations it was appropriate to add a redundant cooler. This allowed us to gain margin. Schedule 7, line 11133861 of Mr. O'Connor's testimony outlines the costs incurred for this modification.<u>Selected cable replacements</u> – We determined that certain underground cables were aging and had reached the end of their life. We had already experienced in-service cable failures so we recognized the need to replace these cables. Further, we had made a commitment as part of our NRC license extension to review these cables as part of our aging management protocols. Our cable management program recommended replacement and we concluded it was appropriate to replace those cables as part of the overall Program. Schedule 7, line 11213813 of Mr. O'Connor's testimony outlines the costs incurred for this modification.

- <u>#13 feedwater heater replacement</u> – Testing of these heaters showed that their replacement was necessary. They were aging equipment and performance was degrading and replacement was necessary in any event. It was decided that it was appropriate to replace those feedwater heaters as part of the LCM/EPU Program to ensure adequate margins were maintained. At the same time, it was determined that the #12 heaters could be rerated (and did not need to be replaced). Thus the overall scope of the Feedwater heater modification included replacing the #13, #14 and #15 heaters. Schedule 7, line 11842626 and 11638897 of Mr. O'Connor's testimony outlines the costs incurred for this modification.
- <u>Stator water cooling heat exchanger replacement</u> – The Site recommended installation of a second heat exchanger for the generator. We concluded that it was necessary to include this second heat exchanger to increase margin and it made sense to undertake this upgrade at the time we rewound the turbine. Schedule 7, line 11286985 of Mr. O'Connor's testimony outlines the costs incurred for this modification.
- <u>RWCU capacity improvements</u> – We needed to ensure that we could process adequate water through our reactor water clean-up system. The existing reactor water clean-up equipment was aging and needed to be replaced in any event to support extended operations and to increase capacity to support increased heat rejection. The modification that was undertaken while the plant was on-line. Schedule 7, line 11286992 of Mr. O'Connor's testimony outlines the costs incurred for this modification.
- <u>Turbine generator vibration system upgrade</u> – Monticello had not previously installed turbine vibration equipment that is standard in the industry. With the installation of the new turbine we decided it was important to install this equipment to track vibration and mitigate against the risk of turbine trips. This equipment was required by our insurance requirement. Schedule 7, line 11335729 of Mr. O'Connor's testimony outlines the costs incurred for this modification.

Finally, many smaller scope changes occurred during the outage implementation process. These were provided in response to DOC IR-50 but do not constitute a substantial portion of the overall Project costs. These items are also outlined in Schedules 19-28 of Mr. O'Connor's testimony.

As described in more detail in our response to DOC-79, internal organizations such as the Site Steering Committee participated with the project team in review and analysis of the Project scope. The Site Steering Committee provided helpful feedback on the operation and maintenance implications of the various modifications. The site team (including the plant manager who sat on the site steering committee) are generally focused on the safe and reliable operation and maintenance of the plant. This operations-focused perspective allowed the plant to provide useful feedback to the Project team when it came to making choices about what modifications to pursue and what how design of the modifications could be undertaken for the benefit of the plant's operators. For example, the Site Steering Committee influenced the decision to implement a 2-pump solution to the reactor feed pump and motors modification, in part by focusing on the ease of operation that would follow from the two-pump solution. By contrast when the Project team decided to replace the six feedwater heaters, plant personnel suggested that certain ancillary equipment should also be replaced. This recommendation was considered but not accepted by the Project team because the ancillary equipment was found to be in good working order and was not needed to support the initiative. Further, by leaving the existing ancillary equipment in place did not create operational difficulties for the operators.

ii. Yes. A Project Manager was responsible to Senior NSP management for the overall LCM/EPU Program scope. The Project Manager was Allan Williams from 2006-2011. After Mr. Williams left the Company, Pat Burke (the overall manager of Nuclear Projects) took over managing the LCM/EPU Program until a permanent replacement was hired. John Bjorseth was hired and became the LCM/EPU Program Manager from 2012-2013.

Preparer:	Mark Schimmel
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Telephone:	612-215-4613
Date:	April 28, 2014

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	80
Requestor:	Nancy Campbell/Chris Shaw		
Date Received:	April 16, 2014		

Question:

Please provide the overall impact of all management decisions identified in 3-2 and 3-3 above on the final costs of the LCM/EPU project.

Response:

At some level, the overall impact of all management decisions made in developing, designing and implementing the LCM/EPU Program was that the overall cost of the Project were about $665 million (as of the August 2013 filing). Updated final costs for the Program (which will be provided as part of our rebuttal testimony) show that the final LCM/EPU Program costs are somewhat lower due to offsets arising since the initial filing. We believe that a substantial portion of this change from the original $320 million ($2008) was due to an underestimation of the effort that it would take to complete the LCM/EPU Project. Even the memo's $362 high-end range estimate shows how much different the actual cost of implementation were compared to what might have been estimated.

Specifically, with respect to Information Request 78 our response with respect to the costs of these management decisions is set forth below:

- *The decision not to bring forward the $362.5 million upper end budget to executive management and the Board:* We are not aware of any impact on LCM/EPU Project costs that were adversely impacted by this decision. The Project Management and staffing was based on our ability to rely on contractors for most of this work. The decision did not impact our decision to either contract with GE nor did it form the scope of work for that Agreement. The Project requested changes shortly after the Project began that brought the total request to approximately $340 million with inflation, so it did not take the Project long to reflect costs much closer to the high end estimate.

- *The decision to move forward with CARV work based on the Company's record drawings from original construction, as opposed preparing as built drawings and installing based on up to date as builts:* The decision to move forward with the CARV work was part of our effort to bring Project benefits to customers earlier to support obtaining additional needed capacity as soon as possible. The earlier proposed implementation date, was anticipated to have provided substantial fuel savings benefits along with capacity at a time we believed it was needed. This was related to the multi-track implementation decision discussed in Mr. O'Connor's direct testimony. As we described in response to DOC IR-78, we do not believe this was a contributor to our overall costs.

- *The decision to elect the 2009 and 2011 schedule rather than the 2011 and 2013 option:* We provide a discussion of the decision to include a third outage and complete implementation in 2013 in our response to DOC IR-41. Also, as we described in our response to DOC-79 there were certain costs and benefits associated with moving forward with a goal of completing the Project by 2011. The fact that we did not include substantial amounts of work in the 2009 outage effectively meant that we implemented this much more like the alternate recommendation in the end. While we did move forward relatively quickly with our 2009 implementation work, we delayed the most complicated aspect of that outage (the condensate demineralizer modification) and this allowed additional time to improve the design for this system. Finally, there is a trade-off between planning costs and the more concurrent implementation approach selected and it is difficult to know by how much these more thorough planning costs will actually offset outage implementation costs or even exceed them.

- *The decision to have the Projects group rather than the Site own ultimate decision rights on the Project:* We do not believe that the Site would have managed the Project more cost-effectively as indicated by Mr. Hammer's memo. To begin with, the operations employees at the Site were already engaged in performing their normal duties to ensure the safe and reliable functioning of the plant. It would not have been realistic or feasible to add oversight of such a major project to those duties without risking operational issues at the plant. This is what led to the decision to have a Project team separate from the Site to be responsible for this and other major projects. Second, Mr. Hammer's memo notes his concern with the reporting structure and his desire for Site control. His concern dated from the prior corporate structure when the plant was operated by the NMC. As we attempted to analyze whether this organizational decision had any impact on costs, we believe that it would require prescience to determine the specific cost results of an alternative Project oversight group when that path was not chosen. This would require significant speculation on what decisions would have and would not have been made. Individuals in the nuclear organization believed that the ultimate key scope decisions were the best and most effective to enable longer term safe, reliable operations of the plant. As such, even if the Site had ownership, it is not clear that the scope would have evolved differently. We do not believe it is reasonable to attribute any costs to the decision on providing the Projects group with the authority to make decisions.

In DOC-79 we highlighted several decisions that may have led to different cost results:

- *The decision to split the work into three outages:* Due to a rejection of equipment due to failure to meet specifications, the concerns that fall of 2011 work packages were not sufficient to begin the outage became a reality, and we later postponed the outage to 2013. Further, since our EPU licensing effort was on hold at this timeframe (due to the NRC) we believed it was appropriate to reconsider the timing of implementation. We initially believed there to be costs associated with the delay due to demobilization and remobilization costs when we were in the outage and assuming a fall 2011 outage. However, there would also have been cost impacts of proceeding with 2011 had that been a reality (higher summer energy purchases) as well as costs of proceeding prematurely with an outage. It is our belief that the costs of this third outage are not materially different than a 2011 and 2013 outage schedule (see above) so there are no additional costs associated with this decision.

- *The decisions to select various vendors including GE, D&Z and Bechtel*: Each of these decisions contributed to the overall Project costs but we do not believe that the issues faced by the contractors would have been avoided by making other selections as many of the vendors in the nuclear area have been experiencing similar quality challenges. Nor do we believe that any of these choices were imprudent.

- *The decision to reject specific equipment:* Generally, the decision to reject equipment through our quality control program decreased customer cost as it avoided and minimized rework after the plant was in-service. Some of the rejected equipment helped drive the decision to postpone the third outage but as explained in Mr. O' Connor's testimony, the unanticipated and unavoidable delay in obtaining the uprate license meant that these manufacturing issues did not contribute to any delay in the ability to implement the uprate.

- *The decisions during implementation regarding various changes and as-found conditions:* Many of these decisions were simply the best means of moving through unexpected conditions during construction, which is typical of many large construction projects.

We did not attempt to quantify the cost of every decision, as many of these were implemented as part of the normal costs of a large and complex construction project and some were part of other decisions for which we believe it is difficult to estimate a cost that was truly additional to the project, versus a potential to have avoided a cost. Overall, the costs incurred in completing the LCM/EPU Program were necessary to achieve the Company's separate goals of (i) ensuring the plant would be positioned to operate safely and reliably for the duration of its extended operating license (2030), and (ii) increasing the capacity of the plant by approximately 71 MWe. In implementing the initiative to achieve these two goals over the course of eight years (2006-13), we made literally hundreds of management decisions that impacted on the scope, implementation, and final costs of the initiative.

The Program was initially proposed based on high-level and conceptual designs. This approach is common in the nuclear power business because of the NRC requirements for nuclear safety and the long lead times required to fully design nuclear modifications. This approach requires the Company to be flexible in its implementation and willing to react to evolving conditions.

In addition, as described in more detail in our response to DOC IR-020, -078, and -079, in prudently managing the LCM/EPU Project, we assessed conditions and current circumstances and changed our implementation to better match the evolving circumstances with which we were faced. We established project management practices that were appropriate to the circumstances we encountered. As the complexity of the job increased, we adapted our practices to address those evolving circumstances. While the Company's filing acknowledges our actions were not perfect during the Program's eight-year duration, the costs we incurred were reasonable and necessary to achieve the desired outcome of upgrading Monticello for an additional 20 years of safe and reliable operations at increased capacity levels.

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Telephone:	612-330-6521
Date:	April 28, 2014

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CI-13-754
(Commission Investigation into
the Monticello LCM/EPU Project)

Date Request Received: July 24, 2014

Date of Response: August 5, 2014

Person Requesting Information: Timothy J. O'Connor

Response submitted by: Mark W. Crisp

Request No.	
9	Re: Direct Testimony and Attachments of Mark W. Crisp Please provide all support for your conclusion that the Board of Directors reduced the project budget and accelerated the timing of implementation other than the Hammer memo. DOC Response: Mr. Hammer's memo to the then Chief Nuclear Officer, Mr. Dennis Koehl speaks for itself. I used no other documentation.

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	48
Requestor:	Campbell/Shaw		
Date Received:	February 28, 2014		

Question:

Please provide a conceptual description of the EPU project which includes the following:

a. A technical description of the overall EPU project that describes the increased outputs of reactor power, steam flow, condensate and feedwater systems, containment accident response, and secondary system changes.

b. A description of how the project was managed within the Xcel organization from project initiation to completion. Include organization charts as they evolved over the years including titles and names of incumbents.

A listing of the major contractors and subcontractors involved including their roles, contracting method, and relationship to Xcel and each other.

Response:[1]

a. The Extended Power Uprate (EPU) Program was developed to increase the NRC licensed output of the station from 1,775 MWth to 2004 MWth with a corresponding increase in electrical generation. An EPU is accomplished by capturing the ability of the reactor and major structures to accommodate more power. However, a large number of secondary components must be replaced

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[1] Note that all documents referred to in this Response will be produced pursuant to and as part of DOC IR-050, which generally seeks documents responsive to all of DOC IR-048 – 064. The Company notes that a number of the documents provided in response to DOC IR-050 contain confidential employee information, Xcel Energy trade secret information, and third-party trade secret information. Documents produced pursuant to DOC IR-050 will be produced with the appropriate designation as part of our response to that information request. The Company chose this method for producing documents to ensure that the responses to the information requests could be disclosed publicly to the maximum extent possible and to avoid any delay that may occur in preparing voluminous confidential documents for production.

or enlarged in order to accommodate the additional steam flow and power output

Fundamentally, the Monticello LCM/EPU Program was an effort to prepare the plant for an additional 20 years of safe, reliable base-load operations by replacing aging components while simultaneously increasing the generating capacity of the Monticello plant by an additional 71 MW(e). As discussed by Witness O'Connor, at the time we made the decision to proceed with the Program, nearly all of the components that required replacement to support the EPU were already being assessed for replacement or upgrade under our LCM initiatives, which were necessary to comply with our license renewal commitments and the NCR's aging management and maintenance rules. In completing the LCM/EPU Program, we made very few modifications to the reactor and the reactor support systems that produce steam. The balance–of-plant systems (or what are sometimes referred in the industry to the "secondary systems) required extensive modification. Many of the power plant systems that convert steam to electricity required replacement. These modifications and replacements increased the size of some components, returned operating margins from aging equipment and brought the plant's equipment up-to-date with current technologies that were simply not available at the time the plant was constructed.

A technical description of the major sub-projects to the balance-of-plant systems is provided below:

Table – Major Modifications Technical Descriptions

Major Modifications	**Technical Description**
Reactor Feed Pumps and Motors system upgrades	This project replaced the feedwater pumps and motors based on the need for more flow to the reactor vessel to support EPU power production and to ensure the reliability of the pumps through life extension. Other components that were replaced as a part of this effort were the feedwater regulating valves, the pump minimum flow valves, portions of piping and supports, and much of the control and monitoring instrumentation.
Condensate pumps and motors system improvements	The condensate pumps and motors were upgraded to provide the increased flow for EPU, new hotwell level controls were installed, and larger motor cooling units were

Major Modifications	**Technical Description**
	built. These upgrades improved the operating margins on equipment that was challenged during summer operations and also improved the reliability of these key components.
13.8kV bus installation	New 13.8kV busses, switchgear and cabling were installed to provide power for the larger power production loads at the station. Removing these loads from the 4kV busses established margin on the existing 4kV busses so that major modifications would not be required to upgrade or replace them to support long term reliable operation. The 13.8kV bus supplies power to the feedwater pumps, reactor recirculation MG sets and the condensate pumps.
Feedwater Heater system reliability	Six feedwater heaters were replaced due to aging concerns with the existing heaters (one failure had already caused a forced outage). In addition, large portions of piping were replaced due to pipe erosion and new flow rates, heater level control valves and instrumentation were upgraded due to obsolescence, the turbine cross around relief valves were replaced and moisture separator drain tank level control improvements were completed.
Condensate demineralizer system upgrade	All five condensate demineralizer vessels and associated internals, piping and valves were replaced due to age related degraded conditions. Larger vessels were installed to accept the increased flow demands of EPU. The process controls were replaced with modern programmable logic controllers as the originally installed controls had to often be operated manually due to failures.
Steam dryer replacement	The reactor steam dryer was replaced due to industry experience with failures and the vulnerability of the Monticello design to those failures, especially under EPU

Major Modifications	Technical Description
	conditions.
Main transformer replacement	The main transformer was replaced at its end of life with one that had additional margin to support the EPU power output.
Main generator rewind	Both the rotor and the stator were rewound as a part of the station life cycle management plan to ensure reliability for at least 20 more years. The rewind allowed the station to improve the generator nameplate rating to provide additional margin for EPU conditions. The exciter was replaced at this time due to end of life considerations.
Power Range Neutron Monitoring system upgrade	As the electronics for the power range neutron system approached end of life, they were upgraded to the industry standard replacements.
High pressure turbine replacement	The old high pressure turbine was replaced with a new monoblock design that removed potential failures due to defects and to replace a system that was aging and would not have been supported for the remainder of the plant's extended license. In addition, this new turbine was designed to support EPU steam flows.
EPU license analysis	The plant was reanalyzed for the EPU power level and for MELLLA+. As a part of the analysis to evaluate operating conditions at EPU conditions, several engineering programs were upgraded to current industry standards. These included the motor operated valve, air operated valve, high energy line break and environmental qualification programs.

A reanalysis of the station was performed which included items such as core and fuel design, safety system requirements, power generation capabilities as well as equipment margins and limitations. A summary of the change in key parameters from the EPU are:

Parameter	Pre-EPU	EPU

Parameter	Pre-EPU	EPU
Reactor Power	1775 MWth	2004 MWth
Nominal Electrical Output	600 MWe	671 MWe
Steam Flow	7.26 Mlbs/hr	8.335 Mlbs/hr
Condensate/Feedwater Flow	7.23 Mlbs/hr	8.302Mlbs/hr
Final Feedwater Temperature	383 degrees F	396 degrees F
Peak Containment Pressure	43.4 psig	44.1 psig
Peak Containment Temperature	273 degrees F	278 degrees F
Peak Torus Water Temperature	194 degrees F	207grees F

b. The management of the LCM/EPU Project evolved over the course of the Project as it progressed through the study, design and implementation phases and as the complexity of the job increased, we adapted our practices to address those evolving circumstances.

We began the necessary tasks of staffing a dedicated project management team in 2006 and early 2007, while the Project was under the control of the Nuclear Management Company ("NMC"). NMC was our contract manager for our nuclear units at that time and was responsible for implementing the LCM/EPU upgrades on our behalf. NMC sought plant personnel to assign to the Project and experienced former employees of the plant and independent contractors to fill remaining positions in the LCM/EPU Project. At that time, NMC made the decision to rely on GE and other third-party vendors for certain aspects of the Project to maximize GE's EPU industry experience and licensing topical reports and also its experience as the original designer of Monticello.

NMC dissolved in 2008, while the EPU Certificate of Need was pending, and the management functions were absorbed back into the Company. 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 our implementation needs we hired union labor through our implementation contractor.

When the Project was under NMC's management, NMC's Vice President and the Chief Nuclear Officer each reported directly to the Xcel Energy President and Chief Operating Officer. After the NMC functions were absorbed back into the Company, the Vice President in charge of the Project as well as the Chief Nuclear Officer positions were created within Xcel Energy. They continued, initially, to report to the Xcel Energy President and Chief Operating Officer.

The reporting relationship changed when the President and Chief Operating Officer retired in early 2010. After his retirement, the LCM/EPU Program management reported up through the Chief Nuclear Officer. This reporting relationship continued until the Vice President-Nuclear Projects retired in March of 2011. Several interim reporting relationships were restructure to split responsibilities between the sites and corporate until a new Vice President-Nuclear Project could be hired in late 2011.

Our experience with the 2011 outage suggested that the final Project modifications scheduled for the 2013 outage would be the most challenging installations of the Project. In mid-2011 we elected to deploy Bechtel Power Corporation ("Bechtel") (who was already doing work for us on other projects) to provide comprehensive project management to ensure successful completion of the final outage. We also hired a new Vice President-Nuclear Projects and reorganized the capital projects organization within the nuclear business unit.

The evolution of the project management structures is described in Mr. O'Connor's testimony pages 55-92 and in our response to DOC IR 20 in this docket. Organizational charts depicting the Project's organizational structure from 2007 through 2012 are included with our document production (*see* the Company's response to DOC IR 50). The Project organizational charts were not created for 2013 because the Project staffers were absorbed into the general nuclear division and contractors were released after implementation of the physical modifications.

The following provides a description of how the project was managed within the Xcel Energy organization throughout the Project phases from initiation to completion.

Study Phase. The initial internal study phase began in 2006, and four individuals were assigned as the core team to lead the effort. The study phase included a preliminary engineering analysis of the capabilities of the equipment and systems, and a review of potential modifications needed to support the EPU based on industry experience and the preliminary engineering analysis. The study phase culminated in a cost estimate and Project plan. General Electric-Hitachi ("GEH"), Monticello's original reactor system designer, was involved with this scoping effort, which allowed Xcel Energy to utilize GEH's EPU experience and Monticello's detailed design information, which GEH maintained. The study phase resulted in the original Nuclear Project Authorization ("NPA") that was submitted to the Finance Committee and approved by the Xcel Energy Board of Directors in August 2006.

Design Phase. After the NPA was authorized, a subject matter expert was designated in 2007 as the Xcel Energy EPU Project Manager. As shown on the 2007 LCM/EPU organizational charts, seven Modification Project Managers reported to the EPU Project Manager. These Project Managers were responsible for the design and implementation of discrete modifications. In addition, the licensing manager reported to the EPU Project Manager and he was responsible for completing the technical analyses necessary to submit the EPU License Amendment Request ("LAR"). Contracts were established with GEH to provide the technical reviews needed to design the Project modifications and GEH subcontracted this effort to Shaw-Stone and Webster ("SSW"). We utilized this contractor approach to minimize the need to hire an internal design team or divert plant resources.

The design phase underwent project management transitions as we proceeded through the Project implementation to ensure the quality and schedule of the modification designs met our expectations. In some instances we utilized other engineering contractors to augment or supplant SSW in developing the EPU modifications.

During the course of the modification development, it became apparent that there would be a need for Xcel Energy support to provide oversight of the modifications. The contracted engineers did not have the station experience needed to ensure the design changes integrated into an operating plant (e.g. – layout and operating constraints, operating experience with specific types of equipment). This drove Xcel Energy to establish a station EPU Project Engineering group within the EPU project in 2009. This group, led by Jim Gausman, performed the reviews of the engineering products and challenged the contractors to ensure modifications were effective.

In 2011, with the major modifications (13.8 kV, reactor feedpumps, condensate pumps) in full development, this group transitioned to the station design engineering group to provide the station ownership necessary to follow these through to completion. This allowed the station to maintain strong ownership through the implementation and closeout phases as contractor resources were reduced.

Implementation Phase. The LCM/EPU implementation phase started in the 2009 refueling outage and continued through the 2013 outage. The Projects department construction organization, headed by Darrell Ostendorf as the Construction Superintendent, implemented the project work in the 2009 and 2011 outages. The prime contractor was Day Zimmerman Nuclear Plant

Services ("DZNPS") for both of these outages. This construction group reported to Pat Burke, the Manager of Projects at Monticello.

For the last cycle of implementation in 2013 we modified several facets of the managerial structure. Al Williams left Xcel Energy in 2011 and John Bjorseth assumed the role of Director of the EPU Project. In December 2011 we hired a new Vice President-Nuclear Projects, Karen Fili, to reorganize the capital projects organization within the nuclear business unit. Ms. Fili is an 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 additional project management controls to assist with oversight of remaining work at Monticello and for other major projects at Prairie Island.

Additionally, for the 2013 refueling outage, Bechtel was contracted to provide the work planning, field engineering, construction management and the craft support needed to install the last major modifications. Bechtel used DZNPS, Collins Electric, Performance Cutting Inc., as well as several other sub-contractors to perform the construction. Xcel Energy retained the management oversight, design engineering and project management functions associated with EPU. This management approach was used through the completion of the construction work.

Testing Phase. Testing was performed on all engineering changes to ensure the modifications performed as expected and upon completion the station assumed ownership of the modifications. This testing function was owned by the station Operations department. For the 2011 outage, Greg Rask, an Assistant Operations Manager, supervised the test development and implementation and he managed station and contracted personnel for this task.

For the 2013 outage, this portion was comprised of two parts: 1) the modification testing described above and, 2) power ascension testing to test the overall plant as power was increased. For both of these aspects, Rick Stadtlander, an Operations Shift Manager, supervised the evolutions.

The overall ownership of EPU transitioned prior to the power ascension testing. John Grubb, Technical Assistant to the Site Vice President, replaced John Bjorseth to provide management oversight of the power ascension testing.

Closeout Phase. Incorporating the documentation from the engineering changes into the plant document control systems was completed as each outage was completed. These closeouts were performed by the station design engineering organization.

The NRC's heightened oversight of project work makes managing compliance critical to a successful outcome. Our record shows strong performance in terms of safety, quality and NRC compliance, which are fundamental priorities in any nuclear project. We were successful in ensuring the work was done well, as demonstrated by the fact that we have thus far experienced no significant equipment issues. Our proactive management was integral to the Project's ultimate success.

c) Listing of major contractors and sub-contractors used for EPU

Contractor Name	Role	Contracting Method	Relationship to Xcel Energy
GE-HITACHI NUCLEAR ENERGY AMERICAS LLC	Primary EPU contractor for Engineering and major equipment.	Fixed scope with additions as T&M	Direct contract
=GE POWER	Sub of GE - Provided GSU, rewound the main generator and replaced the HP turbine		Sub contractor thru GEH
=SHAW NUCLEAR SERVICES (Now Chicago Bridge & Iron)	Prime Engineering Sub of GE - Engineering for Cond. Demin., Condensate Pumps, plus many other mods and started 13.8 kv work.		Sub contractor thru GEH
=SULZER PUMP INC.	Sub of GE - Provided Feedwater pumps		Sub contractor thru GEH
=ELECTRIC MACHINERY CO (Now EM-WEG)	Sub of Sulzer - Built Feedwater motors		Sub contractor thru GEH
=FLOWSERVE PUMP DIV.	Sub of GE - Provided Condensate pumps		Sub contractor thru GEH
=ELECTRIC MACHINERY CO (Now EM-WEG)	Sub of Flowserve - Built Condensate motors		Sub-contractor thru GEH
BECHTEL POWER	Primary construction	Time and	

Contractor Name	Role	Contracting Method	Relationship to Xcel Energy
CORP	contractor from mid 2011 to end of project. Performed work order task planning, field engineering craft and supervision.	Material	
=DAY & ZIMMERMAN	Craft and planning		Sub-contractor to Bechtel
=COLLINS ELECTRIC	Electricians		Sub-contractor to Bechtel
=PCI	Welding services		Sub-contractor to Bechtel
-VIC'S	Heavy hauling and lifting		Sub-contractor to Bechtel
DAY & ZIMMERMAN NPS	Primary construction contractor until mid 2011. Became a subcontractor to Bechtel in 2011.	Time & Material	Direct contract to Xcel Energy
SARGENT & LUNDY, LLC.	Provided work order planning support for the 2009 outage, engineering for Reactor Feedpump and other mods and engineering staff augmentation support.	Time & Material	Direct contract to Xcel Energy
WESTINGHOUSE ELECTRIC COMPANY	Provided engineering, licensing and equipment for Steam Dryer.	Fixed	Direct contract to Xcel Energy
DELTA ENERGY SERVICES, LLC	Provided Project Management core team support.	Time & Material	Direct contract to Xcel Energy
AUTOMATED ENGINEERING SERVICES CORP	Provided engineering for Reactor Feedpumps and related mods as well as engineering staff augmentation support.	Time & Material	Direct contract to Xcel Energy

Contractor Name	Role	Contracting Method	Relationship to Xcel Energy
SUN TECHNICAL SERVICES INC	Staff augmentation support including management, field supervision, specialists and administration.	Time & Material	Direct contract to Xcel Energy
J.D. STEVENSON & ASSOC (STEVENSON & ASSOC)	Provided civil engineering support as well as engineering staff augmentation.	Time & Material	Direct contract to Xcel Energy
BARTLETT NUCLEAR INC	Radiation protection staff augmentation support primarily during the 2011 & 2013 outages.	Time & Material	Direct contract to Xcel Energy
INTERNATIONAL QUALITY CONSULTANTS, INC	Provided quality control/oversight inspection services staff augmentation support during all 3 outages.	Time & Material	Direct contract to Xcel Energy
DELTA STAR INC.	Provided 1R and 2R Transformers.	Per quote	Direct contract to Xcel Energy
PERFORMANCE POWER SERVICES PC	Provided electrical engineering for 13.8 kv as well as engineering staff augmentation.	Time & Material	Direct contract to Xcel Energy

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	028
Requestor:	Nancy Campbell, Chris Shaw & Steve Rakow		
Date Received:	December 10, 2013		

Question:

Reference: Testimony and Schedules of J.A. Stall page 62, lines 10 to 14 stated:

> "With a 40-year-old plant it is unsurprising that the as-built drawings did not completely match the actual as-found conditions. In my interviews with Xcel Energy personnel, I understood that they encountered many instances where field design changes were required as a result of drawing discrepancies."

Please identify what field design changes were required as a result of drawing discrepancies and the estimated cost associated with these field design changes.

Response:

The LCM/EPU Project had numerous construction field changes, approximately 2,000 of which resulted from discrepancies in as-found conditions. Discovering, analyzing and resolving such field changes is a normal part of construction at an operating nuclear plant, particularly one that was constructed 40 years ago.

Each time an unexpected interference was identified we would generate a construction change notice (CCN) that would need to be fully analyzed, approved and implemented to resolve the field change. All field changes related to drawing discrepancies resulted in additional costs being incurred. The costs associated with field changes, however, were not tracked separately in a way to allow us to provide a granular estimate of the specifics of each field change. Rather, all implementation costs were rolled up into the applicable work order. While we did not specifically track the costs of the field changes, in our engineering judgment we assess a total costs associated with the field changes to be in the range of $25,000,000 to $30,000,000.

The complexity of the particular change dictated the amount of time and effort required to resolve it. As described in more detail below, some simple changes were made within a few hours while the most complex changes required hundreds of hours to implement. The more difficult changes required reanalysis, preparation time, review time and approvals before getting sent to the field. Though we are unable to estimate the cost of each field change, in our engineering judgment we believe the field design changes across the entire LCM/EPU Project totaled several million dollars in the aggregate.

The remainder of this response describes the process we used to identify, analyze, implement and resolve field changes that were encountered during implementation.

Primary Cause of Field Changes. Construction field changes were primarily driven from accessibility, interferences and installation complexities. Accessibility was a particularly difficult issue because certain areas in an operating nuclear plant are inaccessible during normal operations due to high levels of radiation or protection of critical safety equipment. This prevented us from undertaking detailed review of actual conditions of these areas prior to the installation outage. Further, some interferences such as the location of rebar, piping and wiring within concrete and behind walls, would not have been apparent even if access to the areas had been available.

Once access was obtained to the normally inaccessible areas during the implementation outage, "as found" field configuration discrepancies were discovered. In many instances we discovered interferences that prevented installation of new equipment and required us to relocate supports or reroute piping or conduit. Structural support locations created another significant impact. Embedded concrete rebar mapping revealed that many of the core bores and supports had to be relocated. Relocating concrete penetrations resulted in redesigning conduit runs and piping systems. When conduits had to be relocated, additional restrictions were placed on the number of bends in order to meet cable pulling force limits. These force limits are specified within the applicable construction codes. The reasons for the existence of such discrepancies are described in our answer to DOC IR-27.

Requirement for Supplemental Analysis. It should be kept in mind that any field change requires supplemental analysis to ensure that the changed configuration still complies with all requirements. For example, if an interference was discovered that required us to move a pipe, we would have to reanalyze the piping and supports to confirm that they still satisfied all applicable structural and safety requirements.

Depending upon the magnitude of the change, this could also require that we reanalyze the interface between the relocated pipe and other systems.

Depending upon the complexity of the field change, this supplemental analysis could range from straightforward to highly complex and iterative. Certain changes could be resolved by reviewing whether the change still fell within the designed tolerances. Other larger changes would need to be reanalyzed to ensure that the affected system still operated properly. For example, if a pipe needed to be rerouted and its supports moved due to interferences, the entire pipe segment would need to be reanalyzed and, if necessary, redesigned to ensure compliance. For the most complex changes, we determined that a change in one system can impact other nearby or related systems, thereby requiring reanalysis of a number of systems.

This analysis was highly iterative. Each time a change was proposed and analyzed, we would have to confirm that the systems worked together in accordance with our standards. This sometimes required multiple rounds of reanalysis, as the "ripple" effects of a particular change were addressed.

Process for Field Changes. We anticipated that we would require field changes during implementation of the LCM/EPU Program and we designed processes and procedures to minimize the disruption and delay that could result. For example, to mitigate the impact of the required reanalysis whenever a change is made, we designed our installations with tolerances in the initial analysis. This meant that in cases where we were required to make a field change but the work remained within the initial tolerances, we could mitigate the amount of time and effort involved in resolving the change. However, with the more significant field changes, we were required to undertake additional analysis and rework.

We also developed specific processes to address the various types of field changes we expected to encounter. In general, throughout the LCM/EPU Project, we used the same process to identify and implement necessary field changes, which can be broken down into three categories: basic, intermediate and complex. This process was based on standard industry practices and provided us with an appropriate way to address field changes as efficiently as possible under the circumstances.

1. Basic Field Changes. The most basic field changes involved construction changes that did not require substantial new engineering analyses or rework. Basic field changes constituted the substantial majority, or about 1,600, of the field changes we encountered during the three outages.

For example, many of our basic field changes were required to work around interferences or structural supports like rebar discovered during actual construction or implementation of the modification. Once a craftsperson encountered an interference in the field, he or she notified the field engineer who then engaged the responsible engineer and the modification project manager and they worked together to draft and approve the CCN required to avoid the interferences. After the construction change was approved, the field engineer revised the construction drawing and re-planned the work order. Once the revised work order was approved, the craftsperson was able to start to construct or implement the work order at the new location.

We used an "at risk" process to minimize lost productivity work hours, which allowed the craft labor to resume work after the construction change was approved, but before the drawing was revised. The "at-risk" process worked well, and we avoided lost work time without incurring the need for significant rework.[1]

We did not track CCN's by category and do not have a precise number of those that fit within the "basic" category. However, the substantial majority of field changes we implemented fell within the basic category, and were often required to move piping or electrical wiring by an inch or two to avoid rebar or other interferences discovered in the field during implementation. In general, we were able to resume construction within two to four hours of identifying the interference and approving the basic field change.

As noted, we did not specifically track the costs of field changes separate from the work order. However, in our engineering judgment, we assess that a typical basic field change cost in a range of $1,000-$10,000. This is based upon a good faith estimate of the tasks that are necessary to identify, assess, and resolve the basic field change, including time for field engineering, preparation, review and approval of the CCN, revised drawings, and planning for implementation. Much of this work was done simultaneously or after implementation of the change to minimize the amount of delay.

We estimate that many of these basic field changes did not create meaningful delay. For others there was a modest amount of delay in deploying work based on the need to adjust craft schedules to accommodate the change. For many of the basic field changes we estimated approximately 20-30 hours of work to fully implement that change. However,

[1] This "at risk" process allowed the responsible engineer to issue an at-risk letter authorizing implementation of the change based on her/his reasonable engineering judgment subject to subsequent confirmation of the design change. The change is at risk until such confirmation is received and the Company would have to rework the change if the subsequent engineering did not support the change. Our experience using this at-risk process was successful and we had no instances where authorized work had to be redone because the subsequent engineering overrode the responsible engineer's judgment.

not all of that time represents lost productivity. Once the need for a CCN was identified there could be some lost productivity in the construction process while the issue was assessed and the CCN prepared. However, once the CCN was prepared (often within an hour or two) we could redeploy the craft labor to complete the revised work without further delay. The remainder of the process is in preparing, processing and implementing the documentation and approvals for the work, which generally could be undertaken simultaneously.

2. Intermediate Field Changes. Intermediate field changes were more complex and generally involved larger changes. We estimate that approximately 400 intermediate field changes. Implementing an intermediate field change involved the similar requirements to revise and approve construction changes, but also included two additional variables: (i) additional design and engineering analysis (often by our third-party vendors) to ensure the revised engineering, piping or supports met our regulatory requirements, and (ii) potential additional construction effort to install the changed system, such as rerouting a pipe or conduit rather than just moving a support due to interferences. More complicated intermediate field changes required actual redesign and engineering changes, and also led to significant additional work in the field.

In our engineering judgment, we assess that a typical intermediate field change cost is in a wide range of $10,000-$250,000, with a majority in the lower end of the range, or an average of $30,000. This is based upon a good faith estimate of the tasks that are necessary to identify, assess, and resolve the intermediate field change, including time for field engineering, preparation, review and approval of the CCN, revised drawings, and planning for implementation. In particular, unlike basic field changes, this category typically included cost to redesign and reengineer equipment to accommodate the change and often involved lengthier installation activities. We estimate that in general we were able to resume construction within 150-175 hours after identifying an intermediate field change. Though the resolution of the intermediate changes took some time, not all of the 150-175 hours was lost productivity time. Instead we were typically able to reassign craft and other laborers to other tasks while we processed the intermediate field changes. Our estimate of intermediate field change costs includes our approximation of delay cost associated with processing the changes.

Examples of more significant intermediate field changes implemented during the LCM/EPU Project along with a good faith estimate of the cost of the change include:

- The steel supports for the condensate demineralizer vessels were oriented differently than depicted on the drawings. This required a redesign of the piping and anchoring systems which went through the supports. (Approximately $100,000.)

- The piping and pipe support for the vent piping in "B" condensate demineralizer vessel was relocated due to interferences with existing structure. (Approximately $200,000.)
- The feedwater heater drawings lacked sufficient detail, which resulted in a portion of the main steam piping having to be removed and reinstalled. (Approximately $100,000.)
- Several of the condensate system recirculation flow piping supports were not reflected on the design drawing. Additional supports and analysis were required to address piping vibration issues. (Approximately $250,000.)
- Due to congestion and final location of the equipment associated with the reactor feed pumps, the raceways needed to be built differently than originally designed. These field changes captured the new configuration for the conduits. (Approximately $200,000.)
- The reactor recirculation motor generator coupling configuration was incorrect on the original drawing. Changes to the motor supports had to be made in the field to install the new motor. (Approximately $100,000.)
- During the installation of the condensate HVAC modification, supports 1 and 5 needed to be relocated to avoid interference with existing large bore piping and existing pipe supports. Support 1 needed to be allowed to move .5 inches above the centerline of the existing beam. Support 5 needed to move approximately 15 inches above the centerline to be placed on the 45 degree elbow, and required use of a 24 inch piece of unistrut. (Approximately $75,000.)
- A support beam on the condensate pump HVAC duct had an interference with the motor terminal box. The beam had to be relocated and coped to allow the terminal box to be accessed. (Approximately $50,000.)

Each of these instances represents more significant, intermediate field changes associated with structural interferences and equipment location differences that required additional design and engineering or additional work during implementation.

3. Complex Field Changes. The final category of field changes consists of those that were markedly complex, impacted electrical or piping systems, or other modifications, and led to significant additional work in the field during implementation. These complex field changes were required to implement the condensate demineralizer and 13.8 kV distribution systems due to the number of interferences encountered and the amount of field engineering that was required to deploy these systems.

In our engineering judgment, we assess that the complex field changes associated with the condensate demineralizer and 13.8 kV systems cost in excess of $1 million. This is based upon a good faith estimate of the tasks that are necessary to identify, assess, and resolve the intermediate field change, including time for field engineering, preparation, review and approval of the CCN, revised drawings, and planning for implementation. In particular, complex field changes required multiple iterations of analysis to address the impacts of design changes on various affected systems.

- *Condensate Demineralizer Field Changes*: During installation of the condensate demineralizer vaults, the piping and electrical runs were rerouted due to the "as-found" rebar locations within the walls and floors. The condensate demineralizer air surge system had limited "as built" drawings developed during original construction, and there were pipe hanger and support interferences identified during the implementation of the modification. Moving these lines required relocation of the concrete core bores, reanalysis of the piping and supports and significant interface between the construction crews and the engineers. This required a highly interative approach to identify piping routes while doing the engineering analysis to support the proposed routing. These activities, including lost productivity attributable to delay, cost in the range of $3 million. For the most part we were able to reassign craft labor while we completed the engineering and analysis for these complex changes and we experienced little delay in processing the field changes required for the condensate system.

- *13.8 kV Distribution System Field Changes*: Implementation of the 13.8 kV system required numerous adjustments to accommodate the as-found configuration of the plant. Thousands of feet of 5-inch conduit was installed in the plant to support the new 13.8 kV power distribution system. Part of this conduit was routed through our 4kV switchgear rooms, which are safety related and provide power to key plant equipment – both on-line and during outages. Those rooms contain protective devices that are very sensitive to vibration, so we could not perform detailed walkdowns of the hanger and support installations until the busses were de-energized for construction. Subsequently, during the installation of the 5-inch conduit and its corresponding supports, there were many construction changes required to avoid interferences and to mount the hangers properly in the ceiling and structure. Again, this was an iterative process between the installation crews and the engineers so that the installation could be constructed while still complying with the applicable codes. Thus, final design and plans for bringing the conduit through those rooms could not be completed until the implementation outage commenced, requiring us to adapt and take 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. We estimate that the cost of the field changes encountered in the 13.8 kV modification at approximately $2 million.

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Date:	January 16, 2014

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Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Office of Attorney General	Information Request No.	6
Requestor:	Ian Dobson		
Date Received:	July 11, 2014		

Question:

Identify all Xcel/NSP individuals, contractors, consultants who participated in the scoping and design for the LCM/EPU. For contractors and consultants provide the amount they were paid in total and for scoping and design activities and identify the time period they provided services.

Response:

In specific response to the question, the Company states that the question is very broad and confusing as to the scope of the information sought. We interpret the question as asking for identification of the principal design engineers who were required to approve and sign final designs for the major modifications undertaken during the LCM/EPU Program. We note that there were many other individuals (employees, staff augmentation contractors, and other design professionals) who worked on the Program and provided input to the principal engineer. It would be unduly burdensome to identify all such individuals. In addition, we interpret the question to be limited to the design work for the modifications undertaken at the plant and is not seeking identification of design engineers at the equipment vendors who participated in the underlying design of the components. It would be unduly burdensome to collect the information on the component design engineers at the equipment manufacturers.

We do not separately categorize contractors as design contractors and many contractors filled multiple or separate roles over the course of the Project implementation; therefore, the scoping and design costs below are estimates. For example, Sargent & Lundy (S&L) personnel provided design support for all or portions of several of the Engineering Change (EC) packages that were created to

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implement the physical modification scope for the LCM/EPU Project. Each Engineering Change was assigned a dedicated Responsible Engineer (RE) accountable for ensuring the design and "issued-for-construction" documents reflected the specific desired/required scope. S&L also provided installation planning support which is not part of the scoping and design process.

For detailed information regarding amounts paid to contractors, see Schedule 3, Appendix A-6 to Mr. Weatherby's Direct Testimony. Attachment A to this response provides a subset of the major contractors who provided scoping and design engineering services in excess of $250,000 in support of the LCM/EPU Program, the amounts paid to these contractors and the time-periods of those contracts.

Table 1 below provides the list of principal Xcel Energy employees accountable for the scoping and design Activities. Table 1 also contains a listing of the primary design contractors, the total amount paid to such contractors and the amount attributable to scoping and design.

Table 2 below provides a list, by EC number, of the REs. REs may be employees of contractors such as S&L, AES, etc. as well as employees of Xcel Energy.

Table 3 includes the minimum quorum members of the Design Review Board and the Design Supervisors who had final approval of the ECs.

Table 1

Xcel/NSP individuals, contractors, consultants who participated in the scoping and design for the LCM/EPU:

Category	**Name**	**Dates**
Employees and Consultants	John Grubb Nate Haskell Rick Rohrer Randy Garding Josh Ohotto Scott Quiggle Jim Gausman Rick Zyduck Mark Lingenfelter Steve Hammer	2004-2009 2004-2013 2007-2008 2008-2011 2009-2012 2009-2012 2010- 2012 2012-2014 2014 2006-2014

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Category	Name	Dates
	Allen Williams John Bjorseth	2007-2011 2010-2014
Contractors	AMEC/AES, Inc. GE-Hitachi J.D. Stevenson & Associates Performance Power Services PC Sargent & Lundy, LLC Westinghouse WDI	See Below

For contractors and consultants provide the amount they were paid in total and for scoping and design activities and identify the time period they provided services.

The original scope of the LCM/EPU program was defined in the 2006 GE contracts. Further scope refinements were made as the design solidified from "conceptual" to "final" and as a result of discovery during installation. For example, the wiring in the Condensate Demineralizer vaults was found to be severely degraded during installation of the new Condensate Demineralizer system. Originally we planned to reuse the wiring, but due to its degraded condition, new wiring had to be installed. This required additional engineering/design work as one would expect. In addition there were examples, as described in the filing, where we engaged other design professionals on certain aspects of the work.

Contractor Name	Role	Time Period	Amount Paid (Total) Approximate Breakout of Scoping and Design Costs
GE-HITACHI NUCLEAR ENERGY AMERICAS LLC (including Shaw Nuclear as chief design subcontractor)	Primary EPU contractor for Engineering and major equipment.	2006-2013	**[Begin Trade Secret…**

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Contractor Name	Role	Time Period	Amount Paid (Total) Approximate Breakout of Scoping and Design Costs
SARGENT & LUNDY, LLC.	Provided work order planning support for the 2009 outage, engineering for Reactor Feedpump and other mods and staff aug. support.	2007-2012	
WESTINGHOUSE ELECTRIC COMPANY	Provided design and equipment for Steam Dryer. Also provided Licensing support for Steam Dryer	2009-2012	
AUTOMATED ENGINEERING SERVICES CORP	Provided piping and piping support design for Reactor Feedpumps and other mods as well.	2006-2012	
J.D. STEVENSON & ASSOC (STEVENSON & ASSOC)	Provided civil/structural design support for Reactor Feedpumps	2007-2011	
PERFORMANCE POWER SERVICES (PPS) PC	Provided electrical design for 13.8 kV system	2008-2013	

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Contractor Name	Role	Time Period	Amount Paid (Total) Approximate Breakout of Scoping and Design Costs
Willoughby & DeChant, Inc (WDI)	Design for the Air Surge Sub - System for Condensate Demineralizer	2009-2013	**Trade Secret Ends]**

Table 2
Responsible Engineers

EC Number and Title	Responsible Engineer
9174 EPU - Flow Induced Vibration Monitoring for EPU Modification to Install Equipment in RFO	NEHLS, JON
9890 EPU – Flow Induced Vibration Monitoring for EPU Modification to	NEHLS, JON
10856 Neutron Monitoring System (PRNM)	ASCHERT, RICHARD
10903 E-12/E-DC-12 Rerate	JENCHURA, JAMES
10915 Reactor Feedwater Pump Replacement	SUNDSETH, DERRICK J
10946 Condensate Pump Replacement	RAGAB, ABDELFATTAH A.
11006 Replacement of Condensate Demineralizers	JACOBSON, RYAN
11018 Replace Main Generator Step-Up Transformer	FRIEBEL, NICK J.
11025 HP Turbine Rotor and HP/LP Turbine Component Upgrades	LORY, BRUCE M.
11125 Torus Attached Piping Support Modifications	KARLS, VINCENT
11126 Balance of Plant Support Modifications	MEHROTRA, KAMAL
11129 Modify Isolated Phase Bus Cooling	ZIGICH, DARIN K
11214 Replace Main Steam and Condensate Flow Transmitters	HUGHES, DAVID O.
11264 FW Flow Transmitters and Process Computer Heat Balance Upgrade	GUTRIDGE, RICHARD
11309 Replace E-13A/B, E-14A/B and E-15A/B Feedwater Heaters	RAGAB, ABDELFATTAH A.
11312 Moisture Separator and Main Steam Drain Tank Level Control	CRAY, MIKE
11444 EPU – 2R and 1R Transformer Upgrades	ANDERSON, SEAN M.
11445 EPU New 13.8 KV Buss 11 and 12 Switchgear Upgrades	ANDERSON, SEAN M.
11734 1AR Transformer Replacement	WALIA, GIAN
11988 Inboard MSIV AVCO 3-way and 4-way Poppet Valve Replacement	PLYMPTON, AUDREY
12037 Modify Process Computer for PRNM Replacement	CRAY, MIKE
12040 Remove Main Steam Thermowell Identified in Task T0316	RAGAB, ABDELFATTAH A.
12172 Feedwater Heater Drain and Dump Valve Replacement (LCM)	RAGAB, ABDELFATTAH A.
12302 Equivalency Evaluation of Extraction Steam Expansion Joints	GUTRIDGE, RICHARD

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– PUBLIC DATA –

EC Number and Title	Responsible Engineer
12332 Generator Rewind and Exciter Replacement Modification	HOUSTON, DONALD
12361 Provide Operations the Ability to Throttle MO-2020 and MO-2021	GUTRIDGE, RICHARD
12401 Condensate Demineralizer Control Panel Replacement	DEHN, ANDREW S
12463 Remove Bricks from the Bioshield to Improve Margin for Potential	KAAS, STEVE
12556 Fire Protection for Main Step-up Transformer	JACOBSON, RYAN
12807 PT-5300 Main Stream Pressure Transmitter Replacement	GUTRIDGE, RICHARD
12816 New Cable 1AR to Buses 15 and 16 (LCM)	JENSEN, DARIN
13086 EQ Transmitter Upgrades for EPU Conditions (Rosemount 1153 to	GUTRIDGE, RICHARD
13195 Replacement of the CARV Discharge Lines and Crossaround Relief	KAAS, STEVE
13578 Turbine-Generator Vibration Monitoring System (LCM)	LORY, BRUCE M.
13629 CDM Semi-Gantry, Vessel Vault Plug Replacement and Monorail	RAGAB, ABDELFATTAH A
13787 13.8 KV Replace Recirc MG Motors	CRAY, MIKE
13808 Turbine Generator Vibration Monitoring System Phase 2	PLETTNER, RODNEY L.
14214 Replace Steam Dryer (required for EPU)	KARLS, VINCENT
14464 Stator Cooling Water Cooling Hx Replacement	LORY, BRUCE M.
14483 RWCU Flow Increase	LEHTO, JOHN M.
14725 EPU – 2R 34.5KV Feeder Replacement Cable Replacement Between	JENSEN, DARIN
15338 Instrumentation for Steam Dryer Replacement	STANKEVITZ, KYLE L.
15342 CDP and RFP Equipment Condition Monitoring	DEHN, ANDREW S
15376 EPU - Condensate Pumps Auxiliary Equipment	CRAY, MIKE
15494 Drywell X-101A Instrumentation Electrical Penetration Assembly	STANKEVITZ, KYLE L.
15566 Replace RFPs – Interference – ESW Reroute	DEMERITT, JARED R
15613 Air Regulator and Actuator Enhancements For PCT AOVs	HINRICHS, MARK
15623 Replace RFPs – interference – Instrument Air Header	SUNDSETH, DERRICK J.
15625 Modify Drain Piping for Feedwater Heaters and 11 FWH Heater Drains	RAGAB, ABDELFATTAH A.
15641 Remove Instrumentation from the New Steam Dryer	FREEMAN, BRIAN D.
15644 Relocate Hot Shop, Oil Storage and Sling Storage Area	PRYHODA, THOMAS J.
15645 EPU – Modification of Current Hot Machine Shop for 13.8 KV Rooms	FITZGERALD, THOMAS J
15703 EPU – Qualification of Floors Under E-13, E-14 and E-15 (A&B)	RAGAB, ABDELFATTAH A
15840 EPU – 13.8 KV Condition Monitoring	DEHN, ANDREW S.
16307 EPU - Condensate Pump HVAC	RAGAB, ABDELFATTAH A.
16423 Lower 4 KV HELB Flood Barrier	LUCKIESH, SCOTT T
16563 Appendix R Hot Short Modifications	JORGENSEN, CRAIG W.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

EC Number and Title	Responsible Engineer
16564 Appendix R Hot Short Modifications	JORGENSEN, CRAIG W.
16738 Feedwater Piping & Reg Valve/ Recirc Valve Replacement	MAR, NATHAN
17236 Electric Pressure Regulator Setpoint Bias	HILL, BILL
18341 EPU – Reroute of FSW Line ESW1-3-HBD in RFP Bay	MAR, NATHAN
18572 RWM Setpoint Changes	BERES, JOEL
20039 Logic Changes to Eliminate OBN of MO-2035	JENSEN, DARIN
20216 EPU Modification to SW Pipe Support SR-350	KAAS, STEVE
20651 ADS Bypass Timer Setpoint Change	BERES, JOEL
21369 Navy Nipple Modification (MSL Drain)	KRAMER, ANNE

Table 3
Design Review Board/Design Supervisors

Category	Name	Dates
Design Review Board Quorum Members	Nate Haskell (Design Eng) Arne Myrabo (Systems Eng) Steve Radebaugh (Maintenance) Bruce MacKissock (Operations) Josh Ohotto (Design Eng) Vas Bardwaj (Systems Eng) Werner Paulhardt (Operations) Steve Mattson (Maintenance) Steve Porter (Systems Eng) Rick Zyduck (Design Eng) Jason Kindred (Systems Eng)	2006-2009 2006-2009 2006-2012 2006-2010 2009-2012 2009-2011 2010- 2012 2011-2012 2011-2013 2012-2013 2013
Attachment C		
Design Supervisors	Josh Ohotto Fred Domke Ed Watzl Jeremiah Hill Randy Garding Scott Quiggle	2007-2009 2006-2007 2007-2013 2012-2013 2007-2013 2007-2013

Portions of this response and Attachment A have been designated as "Non-Public," and Attachment A in its entirety, as they contain information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential vendor pricing and sensitive competitive bidding information that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from their use.

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Thus Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

Preparer:	Mark Schimmel
Title:	Vice President, Nuclear
Department:	Nuclear
Telephone:	612-215-4613
Date:	July 25, 2014

PUBLIC DOCUMENT:
TRADE SECRET INFORMATION AND
NON-PUBLIC DATA EXCISED

Docket No. E002/CI-13-754
OAG Information Request No. 6
Attachment A – Page 1 of 1

Major Contractor Listing – Monticello EPU/LCM Project

NON-PUBLIC DOCUMENT: CONTAINS TRADE SECRET INFORMATION
ENTIRE DOCUMENT IS NON-PUBLIC

Attachment A is marked "NON-PUBLIC" in its entirety as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential vendor pricing and sensitive competitive bidding information that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from their use. Thus Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

PUBLIC DOCUMENT
CONFIDENTIAL INFORMATION EXCISED

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy
Docket No.: E002/GR-12-961
Response To: Office of Attorney General Information Request No. 0048
Requestor: Ron Giteck
Date Received: January 4, 2013 **Supplemented**

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional electric company unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations.

Reference Heuer Direct pg. 46.

(a) Provide an explanation with the associated costs incurred for the Monticello LCM/EPU that were identified as unusable due to changes in scope, NRC requirements or changes in design or other reasons.

(b) Provide a list of all vendors who have provided services, equipment or materials and show the total amounts paid to each vendor for each year 2008 through the test year 2013. Show only amounts for vendors who were paid more than $300,000 in any single year. Also show the amount in total for each year for all vendors that were paid less than $300,000.

Response:

(a) We have not identified any costs incurred for the Monticello LCM/EPU project that we consider unusable due to changes in scope, NRC requirements, changes in design, or other reasons.

(b) Attachment A to this response provides the requested information.

Attachment A has been marked Non-Public in its entirety as it contains information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b).

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This data includes confidential contract terms and this information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy/NSPM maintains this information as a trade secret.

Supplemental Response:

A. As we began responding to information request DOC 160, we determined that there is additional information responsive to this request. While we are still reviewing the project costs, the work and associated costs listed in the table below may be classified as potentially unusable. For purposes of this response, NSPM interpreted the term of "unusable" to mean work that was ultimately not fit for its intended project purpose because of scope changes, changes in NRC requirements, changes in design, or other items. This work may have had other purposes or been a part of a necessary process to optimize the final design of LCM/EPU modifications.

NSPM is continuing to review its project costs in anticipation of filing a prudence review at the conclusion of the Monticello LCM/EPU Project. We expect the final prudence report will include a review of project documentation to identify any work that was ultimately unusable. This review will further quantify the cost of such work and discuss why the work, changes, and decisions were consistent with those that are part of any large construction project at a nuclear facility.

The cost impacts listed in the table below are the Company's best estimates based on available documentation and professional knowledge. While we believe they represent reasonable estimates of the impacts of the items discussed, NSPM is in the process of working with its vendors to develop definitive cost estimates for each piece of work.

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Item #	Description	Estimated Cost	Discussion
1	The portions of the initial License Amendment Request (LAR) submittal were redone following additional questions from the NRC regarding the existing Steam Dryer.	$ 2,391,940	NSPM submitted the initial LAR based on the then existing NRC requirements for steam dryer analyses. Over time the NRC requirements evolved to require a more rigorous analysis of the structural integrity of the steam dryer. That evolution required NSP to withdraw its initial LAR submittal in order to re-perform the steam dryer analysis in a manner that would meet the NRC's revised requirements.
2	The original GE contract scope included analysis and modification of the existing steam dryer. The analysis of the existing steam dryer and potential modifications was abandoned in favor of a replacement steam dryer from Westinghouse.	$ 1,849,995	Due to continuing evolution of the NRC requirements for the steam dryer analysis, NSP made the determination that it was in the best interest of the project to replace the existing steam dryer with a new, more efficient design from Westinghouse. This new steam dryer alleviated the NRC's concerns with respect to the structural integrity of the existing steam dryer at uprated conditions, as well as more efficiently removed excess moisture from the steam that is transferred from the reactor the turbines. That efficiency improvement is expected to lower ongoing maintenance costs and reduce dose to plant personnel.
3	Design work on the 13.8 kV distribution replacement project.	$ 1,800,000	Design work on the 13.8 kV distribution replacement project amounting to $1,800,000 proved unusable due to issues of quality and timing.

PUBLIC DOCUMENT
CONFIDENTIAL INFORMATION EXCISED

Item #	Description	Estimated Cost	Discussion
4	The initial design and location of the 13.8 kV distribution replacement project would have prevented installation of this modification as designed by GE/Shaw.	$ 1,259,685	GE/Shaw's initial design for the 13.8kV system placed the switchgear over plant piping. This would have prevented installation of this modification in the plant do to the inability to access this piping following installation of the switchgear.
5	GEH/ Shaw completed the Torus and Attached Piping analysis to a 208 degree Torus temperature. Upon plant review of the completed calculations, the plant requested 4 degrees of additional margin. GEH issued a Project Change Request to complete this re-analysis. NSP, instead, contracted with another vendor to complete the new analysis and associated summary reports.	$ 352,842	The plant's request was necessary to have acceptable margins of safety.
6	The Equipment Qualification (EQ) program files EQ Part A and B as well as the calculation/file conversions were updated as part of the LCM/EPU Project. Following the completion this work, Monticello chose to perform changes to its HELB analysis and the EQ work was redone to reflect these changes. This is the cost of the contractor work to perform the file conversions (2 years of effort).	$ 302,738	The revisions to the HELB calculations to incorporate conservative assumptions had a downstream impact on the EQ analysis.

PUBLIC DOCUMENT
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Item #	Description	Estimated Cost	Discussion
7	Plant procedures were marked up to reflect changes following implementation of the LAR. Licensing delays resulted in re-performing procedure for those mark-ups to maintain configuration control.	$ 192,449	The plant procedures were revised to prepare the procedures for EPU operations. This is a necessary and required part of performing the uprate. When the NRC was unable to meet its LAR review schedule due to changes to its requirements related to Containment Accident Pressure (CAP) and the steam dryer analysis, NSP was forced to delay implementation of the EPU. It was then necessary to revise the plant procedures to reflect the new equipment installed in the plant, but not yet operating at EPU conditions.
8	As a result of the decision to select Westinghouse for the replacement steam dryer, GE was required to revise two task reports to reflect changes due to the replacement steam dryer.	$ 68,476	Westinghouse's replacement steam dryer was selected due to its better design and anticipated more efficient moisture removal. In addition, Westinghouse provided better terms and conditions under which to procure the replacement steam dryer.
9	Design work on the reactor feed water pumps.	$ 3,000,000	Design work on the reactor feed water pumps work amounting to approximately $3,000,000 proved unusable due to issues of quality and timing.

B. Attachment A to the original response provided the requested information for the years 2008-2012. We are unable to provide a list of expected payments to vendors for the budgeted test year 2013 as we do not budget at the vendor payment level.

PUBLIC DOCUMENT
CONFIDENTIAL INFORMATION EXCISED

Witness:	Anne E. Heuer/Timothy J. O'Connor
Preparer:	Timothy J. O'Connor
Title:	Acting Chief Nuclear Officer
Department:	Nuclear
Telephone:	612-330-7643
Date:	January 17, 2013 **Supplemented: February 4, 2013**

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	123
Requestor:	Nancy Campbell/Chris Shaw		
Date Received:	May 5, 2014		

Question:

Referring to the LCM/EPU Split table shown on Exhibit TJO-1, Schedule 29, page 4 of 6 through 6 of 6, please explain how the Aggregate Cost, Unavoidable LCM Cost and Avoidable EPU Cost for each modification were developed. For example, for the HP Turbine modification the Unavoidable LCM cost of $37.9 million plus the Avoidable EPU cost of $2.3 million do not add up to the Aggregate Cost of $57.3 million. Please explain.

Response:

The list of major project modifications on pages 4-6 of Exhibit TJO-1, Schedule 29, correspond with the respective major modifications of the LCM/EPU project summarized on Tables 15-23 on pages 97-133 of Witness Timothy J. O'Connor's Direct Testimony. Each Table in such testimony lists the specific project work orders included in respective Table. Both the Tables in O'Connor testimony and the Aggregate Cost amounts on pages 4-6 of Exhibit TJO-1, Schedule 29 include common cost allocations.

The Unavoidable LCM and Avoidable EPU amounts on pages 4-6 of Exhibit TJO-1, Schedule 29, correspond with the direct cost assignments summarized on Exhibit TJO-1, Schedule 30, and thus do not include common cost allocations. The Unavoidable LCM and Avoidable EPU amounts on Schedule 29 correspond with the respective work order(s) on Exhibit TJO-1, Schedule 30, and in many cases, the amounts for those columns on Schedule 29 on pages 4-6 include multiple work orders. Again, the specific work orders combined for each major modification of the LCM/EPU project are listed in each corresponding Table in O'Connor testimony on pages 97-133.

For example, the amounts on Schedule 29 for the HP Turbine (shaded in gray in the table below) can be reconciled to the corresponding information in O'Connor testimony Table 15 and Schedule 30 as follows:

HP Turbine *$ in millions*	Total Aggregate Cost (per **Schedule 30)**	Less Common Costs (Total per **Table 15,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
#11133668	$54.0	(16.3)	37.7	37.7	0.0	
#11335729	3.5	(0.9)	2.6	2.3	0.2	0.1
Total costs for this major modification (**Schedule 29** amounts highlighted)	57.5	(17.2)	40.3	40.0	0.2	0.1

Please note that Schedule 29 as filed had some typographical errors in it. Those typographical errors do not impact the overall LCM/EPU split figures. Attachment A to this response is a corrected version of O'Connor Exhibit TJO-1, Schedule 29, with the typographical changes highlighted. The table above reconciles to the corrected version of Schedule 29.

Reconciliations of amounts for other major modifications of the LCM/EPU project, as listed on Schedule 29 (as corrected), to Tables 15-23 of O'Connor testimony and to work order costs listed on Schedule 30 of such testimony are provided as Attachment B to this response.

Preparer: Scott L. Weatherby
Title: Vice President, Nuclear Finance & Business Planning
Department: Nuclear Finance & Planning
Telephone: 612-330-7643
Date: May 15, 2014

CORRECTED

Unavoidable LCM and Avoidable EPU Costs

This Schedule provides a narrative description of the process used to determine the unavoidable LCM costs and the avoidable EPU costs. This narrative description, along with the next schedule which provides the outcomes of the analysis, constitute Xcel Energy's effort to provide the Commission with information to separate the LCM and EPU costs..

We evaluated each LCM/EPU modification (at the child work order level) to assess whether that modification was required in the absence of pursuing an EPU at Monticello. Based on the information available today, this evaluation determined what work was needed on existing equipment to ensure the plant would operate reliably through 2030. We also considered whether unique equipment or implementation was specifically required to support EPU conditions. If we determined different equipment was required, we estimated the incremental cost of such equipment using the the ratio of the uprate capacity (71 MWe) to the pre-EPU output of the plant (585 MWe) or 12.1 percent.

CORRECTED

These evaluations identified the costs that were either unavoidable LCM (that were required absent an uprate), or avoidable EPU (those only needed to support an uprate). For those items with a combination of LCM and EPU costs, we relied on the judgment of the Monticello engineering to apportion the costs between unavoidable LCM and avoidable EPU based on the nature of the vendor services necessary to complete each modification. Finally, we allocated the Project's common costs on a pro rata basis to the two LCM and EPU cost categories.

This analysis provides a reasonable basis to segregate the LCM and EPU costs based on our best engineering judgment and information that we know today. This analysis is similar to the analysis we conducted in connection with the cancelation of the EPU program at our Prairie Island nuclear plant. That analysis was performed in a very similar manner in that we sought to determine what work was required to move forward to operate through the remaining life of the plant. However, several key distinctions exist between the two analyses. The principle distinctions between the analyses performed for the cancellation of the Prairie Island EPU program and the Monticello LCM/EPU Program are:

CORRECTED

- Timing of the analyses
    - The analysis in this Docket was undertaken after the work was completed and based on information we knew following completion of the work, including the condition of components found during the project.
    - The Prairie Island LCM/EPU analysis was completed prior to conducting the physical work, and thus, without the specific knowledge of potential as-found conditions that may be discovered as we complete the work.

- As-Found Conditions
    - The Monticello plant was found to have more systems that needed work than we expected. This plant was originally constructed in the 1960s and the age and condition of many of its components contributed to the assessment of the level of LCM work that was needed.
    - Some significant LCM activities have already occurred at Prairie Island, with the replacement of the steam generator work was done with one unit and is ongoing with the other.

- Type of facility
    - Prairie Island and Monticello are different types of reactors. The Prairie Island units are both pressurized water reactors and the Monticello unit is a boiling water reactor.
    - The differences in the design of these facilities require different investments at different points in time.

CORRECTED

Based on the analysis that we conducted, we are providing the following total amounts for the unavoidable LCM and avoidable EPU costs and the amounts associated with each of the the major modifications.

LCM/EPU Split

LCM/EPU Split	Total Capital $million	LCM Capital $million	EPU Capital $million
Avoidable EPU Scenario	$664.9 (100%)	$518.9 (78.0%)	$146.0 (22.0%)

Unavoidable LCM/Avoidable EPU by Major Modification

Modification	Aggregate Cost	Unavoidable LCM (78.0%)	Avoidable EPU (22.0%)
HP Turbine	$57.5 million	$40.0 million	$0.2 million
	The existing turbine required extensive maintenance or replacement to run through the end of the operating license. Replacing with like or larger was comparable cost. Turbine vibration monitoring equipment required replacement to ensure continued station operation but was more complicated and a portion was allocated to EPU.		
PRNM	$17.5 million	$12.2 million	--
	The PRNM system would have eventually been needed due to aging and lack of spare parts and did not require any additional equipment or analysis related to the EPU.		
Steam Dryer	$37.7 million	$30.4 million	$5.1 million
	The steam dryer required replacement to ensure continued operation through the operating license term. Steam dryer acoustic monitoring was an EPU requirement.		

CORRECTED

Modification	Aggregate Cost	Unavoidable LCM (78.0%)	Avoidable EPU (22.0%)
Condensate Demineralizer	$79.8 million	$48.3 million	$16.1 million
	Replacement of the five vessels necessary to support continued plant operation but 25 percent of the cost was attributed to EPU for larger equipment. Control system, valves, wiring, and piping required replacement to support continued plant operation.		
Transformer	$29.9 million	$19.4 million	$1.9 million
	Replacement of 1AR transformer necessary due to equipment obsolescence and continued plant operation. Replacement of main power transformer necessary due to equipment obsolescence, but equipment is larger for EPU.		
Feedwater Heaters	$114.9 million	$79.6 million	$9.3 million
	Feedwater heaters, valves, and piping required replacement to support continued operation of the station. Modification to drain tank all EPU. Increased size of heaters, piping, and valves attributed to EPU.		
Reactor Feed Pumps and Motors	$92.2 million	$77.8 million	$5.7 million
	Equipment required replacement to support continued operation of the station. Larger equipment costs attributed to EPU.		
Condensate Pump and Motor	$21.9 million	$5.0 million	$14.8 million
	Pump replacement was an EPU requirement. Replacement of the motors was necessary to ensure operation of the station through the current operating license term.		
13.8 kV System	$119.5 million	$108.4 million	--
	Existing 4 kV system breakers are no longer manufactured. Cost of 13.8 kV comparable to required 4 kV system modifications.		

Docket No. E002/CI-13-754
DOC Information Request No. 123
Attachment A - Page 6 of 6

CORRECTED

Northern States Power Company

Docket No. E002/CI-13-754
Exhibit___(TJO-1), Schedule 29
Page 6 of 6

Modification	Aggregate Cost	Unavoidable LCM (78.0%)	Avoidable EPU (22.0%)
Licensing	$59.3 million	--	$59.3 million
	Licensing work all allocated to EPU.		
Other Modifications	$34.6 million	$25.2 million	$1.5 million
	Other Modifications. See Exhibit ___ (TJO-1), Schedule 30.		
Common Cost Allocation	$0.1 million	$78.6 million	$25.8 million
	Although most costs were directly assigned, some costs were considered common in nature (i.e., not readily attributable to either LCM or EPU) or were smaller costs remaining after the larger cost items were reviewed and assigned. These remaining common and other costs were then allocated pro rata to costs that were directly assigned to unavoidable LCM or avoidable EPU under the process described above.		
Totals	**$664.9 million Total Capital**	**$518.9 million Unavoidable LCM**	**$146.0 million Avoidable EPU**

Reconciliation of Major Modification Costs from Tables 15-23 of O'Connor Testimony to Schedules 29-30

HP Turbine *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 15,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 11133668	$54.0	(16.3)	37.7	37.7	0.0	
W.O. 11335729	3.5	(0.9)	2.6	2.3	0.2	0.1
Total costs for this major modification (**Schedule 29** amounts highlighted)	57.5	(17.2)	40.3	40.0	0.2	0.1

Power Range Neutron Monitor (PRNM) *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 16,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 10942850	17.5	(5.3)	12.2	12.2	--	
Total costs for this major modification (**Schedule 29** amounts highlighted)	17.5	(5.3)	12.2	12.2	--	--

Note: Schedule 29 amounts on these tables refer to corrected version, included on DOC IR 123 Attachment A

Reconciliation of Major Modification Costs from Tables 15-23 of O'Connor Testimony to Schedules 29-30

Steam Dryer *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 17,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 10859413	$7.3	(2.2)	5.1	--	5.1	
W.O. 11215274	30.4	(0.0)	2.6	30.4	--	
Total costs for this major modification (**Schedule 29** amounts highlighted)	37.7	(2.2)	35.5	30.4	5.1	--

Condensate Demineralizer *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 18,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 11133705	79.8	(15.4)	64.4	48.3	16.1	
Total costs for this major modification (**Schedule 29** amounts highlighted)	79.8	(15.4)	64.4	48.3	16.1	--

Note: Schedule 29 amounts on these tables refer to corrected version, included on DOC IR 123 Attachment A

Reconciliation of Major Modification Costs from Tables 15-23 of O'Connor Testimony to Schedules 29-30

Transformer *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 19,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 10943007	$26.5	(7.6)	18.9	17.0	1.9	
W.O. 10735617	3.4	(1.0)	2.4	2.4	--	
Total costs for this major modification (**Schedule 29** amounts highlighted)	29.9	(8.6)	21.3	19.4	1.9	--

Reactor Feed Pumps *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 21,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 11286955	92.2	(8.6)	83.5	77.8	5.7	
Total costs for this major modification (**Schedule 29** amounts highlighted)	92.2	(8.6)	83.5	77.8	5.7	--

Note: Schedule 29 amounts on these tables refer to corrected version, included on DOC IR 123 Attachment A

Reconciliation of Major Modification Costs from Tables 15-23 of O'Connor Testimony to Schedules 29-30

Feedwater Heater *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 20,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 11638897/11842626	49.2	(4.4)	44.7	36.2	8.5	
W.O. 11133719	4.7	(1.4)	3.3	3.3	--	
W.O. 11284286	17.6	(5.0)	12.6	12.6	--	
W.O. 11286961/11757884	24.8	(9.4)	15.4	8.9	6.6	
W.O. 11133856	0.3	(0.1)	0.2	--	0.2	
W.O. 11133713	18.4	(5.5)	12.8	12.6	0.3	(0.1)
W.O. 11286981	0.0	0.0	0.0	--	--	
W.O. 11376086/11376103	--	--	--	--	--	
Rounding	(0.1)	--	0.1			
Total costs for this major modification (**Schedule 29** amounts highlighted)	114.9	(25.8)	89.1	73.6	15.6	(0.1)

Note: Schedule 29 amounts on these tables refer to corrected version, included on DOC IR 123 Attachment A

Reconciliation of Major Modification Costs from Tables 15-23 of O'Connor Testimony to Schedules 29-30

Condensate Pumps *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 22,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 10943052/11845189	21.9	(2.0)	19.8	5.0	14.8	
Total costs for this major modification (**Schedule 29** amounts highlighted)	21.9	(2.0)	19.8	5.0	14.8	--

13.8kV System *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (Total per **Table 23,** W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 11257804	119.5	(11.2)	108.3	108.4	--	
Total costs for this major modification (**Schedule 29** amounts highlighted)	119.5	(11.2)	108.3	108.4	--	(0.1)

Note: Schedule 29 amounts on these tables refer to corrected version, included on DOC IR 123 Attachment A

Reconciliation of Major Modification Costs in O'Connor Testimony Schedules 29-30

Licensing *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 11536446/11775097 & 5 in 11636xxx series	59.3	(0.1)	59.3	--	59.3	
Total costs for this major modification (**Schedule 29** amounts highlighted)	59.3	(0.1)	59.3	--	59.3	--

Common Cost Allocation *$ in millions*	Total Aggregate Cost (after common cost allocations) per **Schedule 30**	Less Common Costs Allocated (W.O. detail per **Schedule 30)**	Gross Common Costs to be Allocated (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 10435578	0.1	(104.3)	104.4	78.6	25.8	(0.1)
Total costs for this major modification (**Schedule 29** amounts highlighted)	0.1	(104.3)	104.4	78.6	25.8	(0.1)

Note: Schedule 29 amounts on these tables refer to corrected version, included on DOC IR 123 Attachment A

Other Modifications *$ in millions*	Total Aggregate Cost (including common cost allocations) per **Schedule 30**	Less Common Costs (W.O. detail per **Schedule 30)**	Net Costs Direct Assigned (on **Schedule 30**)	Unavoidable LCM portion (W.O. detail per **Schedule 30)**	Avoidable EPU portion (W.O. detail per **Schedule 30)**	Rounding
Work orders included in this major modification:	From column titled "Aug '13 Actuals with allocations"	Schedule 30 amts from column titled "Remove allocations included"	From column titled "Aug '13 Actuals w/o allocations"	From **LCM** column at far right	From **EPU** column at far right	
W.O. 10943047	2.6	(0.8)	1.8	1.8	--	
W.O. 11132414	7.0	(2.1)	4.9	4.9	--	
W.O. 11133731	0.5	(0.1)	0.3	0.3	--	
W.O. 11133861	5.4	(1.6)	3.8	3.8	--	
W.O. 11133865	0.8	(0.3)	0.6	0.6	--	
W.O. 11194611	0.6	(0.2)	0.4	0.4	--	
W.O. 11225964	0.4	(0.1)	0.3	0.3	--	
W.O. 11286966	6.7	(0.9)	5.7	5.7	--	
W.O. 11286973	0.1	(0.1)	0.0	--	--	
W.O. 11286985	2.4	(0.7)	1.7	1.7	--	
W.O. 11133877	0.1	(0.0)	0.1	--	0.1	
W.O. 11133931	0.2	(0.1)	0.2	--	0.2	
W.O. 11398720/11776513	1.2	(0.1)	1.1	--	1.1	
W.O. 11133871	0.3	(0.1)	0.2	0.2	--	
W.O. 11286992	5.7	(0.5)	5.1	5.0	0.1	
W.O. 11410738	0.4	(0.0)	0.4	0.4	--	
Rounding	0.2	(0.2)	0.3	0.1	0.0	0.2
Total costs -other mods (**Sched. 29** amts highlighted)	34.6	(7.9)	26.9	25.2	1.5	0.2

Note: Schedule 29 amounts on these tables refer to corrected version, included on DOC IR 123 Attachment A

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	58
Requestor:	Campbell/Shaw		
Date Received:	February 28, 2014		

Question:

For each work order listed on Exhibit (TJO-1), Schedule 5 to Timothy J. O'Connor's testimony of November 4, 2013 in E002/GR-13-868, please identify whether the work order is necessary for the EPU project, the LCM project or necessary for both. Please explain in detail the basis and criteria used in deciding whether each work order was needed for the EPU project, the LCM project or both.

Response:[1]

Exhibit (TJO-1), Schedule 5 to my direct testimony of November 4, 2013 in E002/GR-13-868 is the LCM/EPU Modification In-Service Table for the LCM/EPU Project. That schedule was also submitted as part of this docket as Exhibit (TJO-1), Schedule 5 to my testimony of October 18, 2013 in E002/CI-13-754. All work orders listed on those schedules are included in Schedule 30 of my testimony in this docket (E002/CI-13-754), in which the Company addresses the information sought in this Request.

Specifically, Schedule 30 categorizes all the work orders into: (1) LCM-only work - not avoidable in the absence of an uprate; (2) EPU-only work - could have been avoided in the absence of an uprate; (3) LCM Work with some incremental EPU costs (e.g. equipment changes); and (4) Common costs. The total Monticello LCM/EPU Project costs on Schedule 30 is $664.9 million (August 2013 actual spend). Schedule 30 includes a column which indicates whether the equipment was needed without the

[1] Note that all documents referred to in this Response will be produced pursuant to and as part of DOC IR-050, which generally seeks documents responsive to all of DOC IR-048 – 064. The Company notes that a number of the documents provided in response to DOC IR-050 contain confidential employee information, Xcel Energy trade secret information, and third-party trade secret information. Documents produced pursuant to DOC IR-050 will be produced with the appropriate designation as part of our response to that information request. The Company chose this method for producing documents to ensure that the responses to the information requests could be disclosed publicly to the maximum extent possible and to avoid any delay that may occur in preparing voluminous confidential documents for production.

EPU and a separate column describing the reason for the unavoidable LCM work, such as obsolescence due to the equipment being at the end of life. As part of this Response we are providing, as Attachment A to this response, a supplemented Schedule 30 to my testimony in this case with expanded explanations for the unavoidable LCM work for various modifications. For further information regarding technical aspects of the installed equipment and various alternatives investigated for the modifications see the Responses to DOC-49 and DOC-57.

Additionally, the Company provided Schedule 29 to my testimony in this docket (E002/CI-13-754), which describes in narrative form the process and criteria the Company used to group the work orders listed in Schedule 5 into the categories listed above.

Overall, we evaluated each LCM/EPU modification (at the child work order level) to assess whether the modification was required in the absence of pursuing an EPU at Monticello. Based on the information available today, this evaluation determined what work was needed on existing equipment to ensure the plant would operate reliably through 2030. We also considered whether unique equipment or implementation was specifically required to support EPU conditions. If we determined different equipment was required, we estimated the incremental cost of such equipment using the ratio of the uprate capacity (71 MWe) to the pre-EPU output of the plant (585 MWe) or 12.1 percent. Without specific cost data for both uprate and non-uprate sized equipment, this ratio accurately reflects the incremental increase in the capacity at the plant and therefore was an appropriate proxy for such costs.

These evaluations identified the costs that were either unavoidable LCM (that were required absent an uprate), or avoidable EPU (those only needed to support an uprate). For those items with a combination of LCM and EPU costs, we relied on the judgment of the Monticello engineering to apportion the costs between unavoidable LCM and avoidable EPU based on the nature of the vendor services necessary to complete each modification. Finally, we allocated the Project's common costs on a pro rata basis to the two LCM and EPU cost categories.

Preparer:	Timothy J. O'Connor
Title:	Chief Nuclear Officer
Department:	Nuclear
Telephone:	612-330-6521
Date:	March 13, 2014

Monticello LCM/EPU Work Orders - LCM vs EPU Split ($ in millions)

#	Child W O No.	Modification	Aug '13 Actuals with allocations	Direct Charge to WO(incl GE)	GE Equipmt Direct Assign	GE Licensing Direct Assign	GE Other Direct Assign	Othr Licensing Direct Assign	GE Common Allocation	Othr Common Allocation	Remove Allocations Included	Aug '13 Actuals w/o allocations	Materials/ Equipmt Incl v	Equipment needed without EPU?	Addtl equipment (Eq) or implementation needed for EPU?	EPU Est. incremental / avoidable EPU cost ($M)	LCM Unavoidable LCM / Other Costs ($M)
		LCM-only work - not avoidable in the absence of an uprate															
1	10942850	MNGP EPU-Power Range Neutron Monitor	$17.5	7.4	4.8				0.9	4.4	(5.3)	12.2		Yes	No	-	12.2
2	10943047	MNGP EPU GEZIP Installation (Zinc Injection Passivization)	$2.6	1.5	0.4				0.1	0.7	(0.8)	1.8		Yes	No	-	1.8
3	11132414	MNGP EPU Expansion Joints	$7.0	4.9					0.4	1.8	(2.1)	4.9		Yes	No	-	4.9
4	11133668	MNGP EPU Turbine Replacement	$54.0	5.3	32.4				2.8	13.5	(16.3)	37.7		Yes	Yes Eq , but comparable cost	-	37.7
5	11133719	EPU Feedwater Heater Drain & Dump Valve Replacement	$4.7	3.3					0.2	1.2	(1.4)	3.3		Yes	No	-	3.3
6	11133731	EPU Main Steam Flow Transmitters Replacement	$0.5	0.2			0.1		0.0	0.1	(0.1)	0.3		Yes	No	-	0.3
7	11133861	EPU Isophase Bus Cooling Replacement	$5.4	2.4	0.2		1.2		0.3	1.4	(1.6)	3.8		Yes	No	-	3.8
8	11133865	EPU EQ Transmitters & Detectors	$0.8	0.6					0.0	0.2	(0.3)	0.6		Yes	No	-	0.6
9	11194611	EPU Off Gas Dilution Fan Cable	$0.6	0.4					0.0	0.2	(0.2)	0.4		Yes	No	-	0.4
10	11215274	EPU Steam Dryer Replacement	$30.4	30.4					-	0.0	(0.0)	30.4		Yes	No	-	30.4
11	11225964	EPU Acoustic Monitoring Instrumentation	$0.4	0.3					0.0	0.1	(0.1)	0.3		Yes	No	-	0.3
12	11257804	MNGP EPU 13.8 kV Distribution System	$119.5	107.9	0.4				0.1	11.1	(11.2)	108.4		Yes	Yes Eq , but comparable cost	-	108.4
13	11284286	MNGP EPU Replacement 4 Feedwater Drain & Dump Valves	$17.6	6.9	0.9		4.8		0.8	4.1	(5.0)	12.6		Yes	No	-	12.6
14	11286966	MNGP EPU Generator Field Rewind	$6.7	5.7					0.2	0.8	(0.9)	5.7		Yes	No	-	5.7
15	11286973	MNGP EPU Generator Exciter Replacement	$0.1	0.0					0.0	0.1	(0.1)	0.0		Yes	No	-	0.0
16	11286985	MNGP EPU Stator Water Cooler Replacement	$2.4	1.7					0.1	0.6	(0.7)	1.7		Yes	No	-	1.7
17	10735617	MNGP EPU 1AR Transformer Replacement	$3.4	1.6	0.0		0.7		0.2	0.9	(1.0)	2.4		Yes	No	-	2.4
	9	Contingencies - Later assigned to individual child work orders	$0.0	-						-	-	-		Yes	No	-	-
		Subtotal - Items fully Unavoidable regardless of EPU	$273.8	180.6	39.2	-	6.8	-	6.2	41.0	(47.2)	226.6				-	226.6
		EPU-only work - Could have been avoided in the absence of an uprate														EPU	LCM
18	10859413	MNGP EPU Steam Dryer Acoustic Monitoring	$7.3	5.1					0.4	1.8	(2.2)	5.1		No	Yes	5.1	-
19	11133877	EPU Removal of Drywell Bricks in Bioshield	$0.1	0.1						-	-	0.1		No	Yes	0.1	-
20	11133856	EPU Feedwater Flow Transmitters/Programmable Control In	$0.3	0.2			0.1		0.0	0.1	(0.1)	0.2		No	Yes	0.2	-
21	11133931	EPU Drywell Spray Flow Valve Replacement	$0.2	0.1			0.0		0.0	0.1	(0.1)	0.2		No	Yes	0.2	-
22	11286981	MNGP EPU Main Steam Drain Tank Modifications	($0.0)	(1.6)			1.6		-	-	-	(0.0)		No	Yes - see line 36 below	(0.0)	-
23	11398720	Engineering & Supervision for EPU	($0.0)	(0.0)						-	-	(0.0)		No	Yes	(0.0)	-
24	11776513	EPU Steam Dryer Instrumentation Removal	$1.2	1.1					-	0.1	(0.1)	1.1		No -driven by EPU	Yes	1.1	-
25	11536446 / +5 11636xxx wo's + 11775097	MNGP EPU License Development	$59.3	10.3	-	25.3		23.7	0.0	0.0	(0.1)	59.3		No	Yes	59.3	-
		Subtotal - Items fully related to EPU, which would have been avoidable were an EPU not completed	$68.5	15.3	-	25.3	1.7	23.7	0.4	2.1	(2.5)	66.0				66.0	-
		LCM Work with some incremental EPU costs (e.g. equipment changes)											Assumed upsize for EPU = this % of equipmt cost>>			EPU 12.1%	LCM
26	10943007	MNGP EPU Main Power Transformer	$26.5	9.2	9.7				1.3	6.3	(7.6)	18.9	15.5	Yes	Yes - Eq larger	1.9	17.0
27	10943052 & 11845189	MNGP EPU Condensate Impeller/Pumps/Motors	$21.9	17.9	0.2		1.7		0.0	2.0	(2.0)	19.8	3.4	Motors - Yes (LCM) Pumps - No	Motors - No ($5M LCM) Pumps -Yes (all remainder)	14.8	5.0
28	11133705	EPU Condensate Demineralizer System Replacement	$79.8	41.5	1.0		21.9		2.6	12.7	(15.4)	64.4	10.9	See below	See below	See below	See below
28a		Replace 5 vessels & related piping									-	-		No	Yes:estimate@ 25% of modification cost	16.1	
28b		Control systems & valves w/h needed replacemt									-	-		Yes - remainder	No		48.3
29	11133713	EPU Cross Around Relief Valves (CARV) Replacement	$18.4	8.6	0.3		4.0		0.9	4.6	(5.5)	12.8	3.2	Yes	Special tests - est@ $250k	0.3	12.6
30	11133871	EPU Main Steam Isolation Valve Solenoid Valve Replacement	$0.3	0.2					0.0	0.1	(0.1)	0.2	0.2	Yes	Yes - Eq larger	0.0	0.2
31	11286955	MNGP EPU Replacement of Reactor Feedwater Pumps/Motors	$92.2	78.2			5.3		0.1	8.5	(8.6)	83.5	6.1	Yes	Yes - Eq larger plus more installation (est @ $5M)	5.7	77.8
32	11286961 & 11757884	MNGP EPU Replacement of 14 and 15 A/B Feedwater Heaters	$24.8	8.4			7.0		-	9.4	(9.4)	15.4	4.6	Yes	Yes - Eq larger and $6M for floor replacement	6.6	8.9
33	11286992	MNGP EPU Reactor Water Clean Up Capacity Improvement	$5.7	5.1					0.0	0.5	(0.5)	5.1	0.9	Yes	Yes - Eq larger	0.1	5.0
34	11335729	MNGP EPU Turbine Generator Vibration	$3.5	2.6					0.2	0.7	(0.9)	2.6	0.5	Yes	Yes-Eq 50% more complex	0.2	2.3
35	11410738	MNGP EPU PCT Vent & Purge Valves	$0.4	0.4					0.0	0.0	(0.0)	0.4	0.0	Yes	Yes-AppR cable only	0.0	0.4
36	11638897 & 11842626	MNGP EPU 13 A/B Feedwater Heater Replacements	$49.2	44.7					0.0	4.4	(4.4)	44.7	4.3	Yes	Yes - $8M in Tank drain is EPU, plus other Eq larger	8.5	36.2
		Subtotal - Items that are mainly unavoidable LCM costs, but also with incrementally avoidable EPU costs	$322.5	216.9	11.1	-	40.0	-	5.2	49.3	(54.5)	268.0				54.3	213.7
		COMMON COSTS															
37	10435578	MNGP Extended Power Uprate - **COMMON COSTS**	$0.1	252.1	(50.3)	(25.3)	(48.5)	(23.7)	(11.8)	(92.5)	104.3	104.4	N/A	N/A - see Common workorder worksheet		25.8	78.6
		Total Monticello LCM/EPU Project	$664.9	$664.9	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$664.9		Estimated Split of Avoidable EPU vs. LCM		EPU $146.0 (22.0%)	LCM $518.9 (78.0%)

Total Direct Assigned	EPU	LCM
Child WO's	$ 120.2	$ 440.3
Common	$ 11.1	$ 21.1
Total	$ 131.4	$ 461.4
	22.2%	*77.8%*

89.1% $ 592.8

	Total	EPU	LCM
Direct Assigned child WO	$ 560.6	$ 120.2	$ 440.3
Ratio of direct assigned child WO costs		21.45%	78.55%
% of total project costs	*84.3%*		

Monticello LCM/EPU Work Orders - Description of why work was unavoidable LCM vs. avoidable EPU

	LCM-only work - not avoidable in the absence of an uprate		Equipment needed without EPU?	Reason for unavoidable LCM work, if not avoidable EPU work
1	10942850	MNGP EPU-Power Range Neutron Monitor	Yes	The Company was experiencing difficulting with spare parts availability and obsolescence of the equipment. The power range neutron monitoring system had been in service for over 40 years. The availability of spare parts was becoming problematic for maintaining the existing system. The analog system was scheduled for replacement in support of life extension.
2	10943047	MNGP EPU GEZIP Installation (Zinc Injection Passivization)	Yes	The Company was experiencing difficulty in performing maintenance on this system. It had become harder and more expensive to get zinc (powdered) for pumped system. The vendor had transitioned to passive injection system approach with pellitized zinc.
3	11132414	MNGP EPU Expansion Joints	Yes	This system was experiencing spare parts availability and obsolescence issues. It was necessary to replace this system to ensure safe operation to end of plant life. Specifically, one expansion joint had developed a hole and required replacement. Because the Company had to replace one joint, it was prudent to replace all joints to avoid duplicate mobilization charges.
4	11133668	MNGP EPU Turbine Replacement	Yes	The previously installed turbine rotor would have reached end of life prior to end of plant life, therefore requiring replacement to run through the end of plant life. This LCM replacement was pulled forward from original long range plans in order to efficiently use plant resources.
5	11133719	EPU Feedwater Heater Drain & Dump Valve Replacement	Yes	The equipment needed to be replaced due to obsolescence. It was necessary to replace as scheduled, as these valves were essentially at end of life, to ensure safe operation through end of plant life. It was appropriate to combine this required replacement with the EPU project for efficient use of plant resources.
6	11133731	EPU Main Steam Flow Transmitters Replacement	Yes	This equipment needed to be replaced due to obsolescence. It was necessary to replace to ensure safe operation until the end of the plant life to meet equipment maintenance requirements. Additionally predicted radiation levels impacted equipment life. The replacement would have been required at some point in the remaining plant extended period of operation.
7	11133861	EPU Isophase Bus Cooling Replacement	Yes	The isosphase system was one of the remaining Single Point Vulnerability systems in plant. This was a key strategy in improving overall plant safety, reliability and availabililty. It was necessary to replace as scheduled to ensure continued safe operation of plant through end of life.
8	11133865	EPU EQ Transmitters & Detectors	Yes	The equipment needed to be replaced due to obsolescence. It was necessary to replace at some point to ensure safe operation to end of plant life to meet equipment maintenance requirements. Additionally predicted radiation levels impacted equipment life. The replacement would have been required at some point in the remaining plant extended period of life.
9	11194611	EPU Off Gas Dilution Fan Cable	Yes	This cable was slightly undersized for its service and at the end of its life due to insulation. Under the station's cable aging management program it was scheduled for replacement. It was necessary to replace as scheduled to ensure safe operation of plant.
10	11215274	EPU Steam Dryer Replacement	Yes	Necessary to replace at some point to ensure safe operation to end of plant life. The existing steam dryer would not have lasted through 2030.
11	11225964	EPU Acoustic Monitoring Instrumentation	Yes	Would be required by NRC for any dryer replacement due to end of life issues with existing dryer.
12	11257804	MNGP EPU 13.8 kV Distribution System	Yes	The equipment needed to be replaced due to obsolescence. The 4kV system consisted of 6 buses and ~36 cubicles. Buses 11 &12 were replaced with 13.8 project. It will be necessary to replace or upgrade some (or all) of the remaining 4kv buses and breakers at some point in the plant's period of extended operation to ensure safe operation of the plant through the end of life. The 4kv breakers are horizontal magnablast breakers that are no longer manufactured by GE which has resulted in increasing difficulty in maintenance, reliability, and availability issues with adequate spare parts for rebuild. The addition of the 13.8kV buses freed up several additional cubicles in addition to 4KV breakers spares for use in maintaining the remaining 4 kV breakers.
13	11284286	MNGP EPU Replacement 4 Feedwater Drain & Dump Valves	Yes	The equipment needed to be replaced due to obsolescence. It was necessary to replace as scheduled (because the valves were at end of life) to ensure safe operation through end of plant life. It was appropriate to combine this required replacement with EPU for project implementation efficiency.
14	11286966	MNGP EPU Generator Field Rewind	Yes	It was necessary to rewind at some point sooner as opposed to later to ensure continued operation of plant to end of life.
15	11286973	MNGP EPU Generator Exciter Replacement	Yes	The equipment needed to be replaced because of obsolescence. It was necessary to replace as scheduled to ensure reliable operation of plant - end of life issue.
16	11286985	MNGP EPU Stator Water Cooler Replacement	Yes	This equipment needed to be replaced due to obsolescence. It was necessary to provide second heat exchanger as scheduled to ensure safe operation of plant - single point vulnerability issue. Also, existing heat exchanger was approaching end of life.
17	10735617	MNGP EPU 1AR Transformer Replacement	Yes	The equipment needed to be replaced due to obsolescence. The replaced transformer was over 60 years old and the oil testing was showing signs of advanced aging. It was necessary to replace as scheduled to ensure continued safe operation of plant - end of life issue.

Monticello LCM/EPU Work Orders - Description of why work was unavoidable LCM vs. avoidable EPU

	LCM-only work - not avoidable in the absence of an uprate		Equipment needed without EPU?	Reason for unavoidable LCM work, if not avoidable EPU work
	EPU-only work - Could have been avoided in the absence of an uprate			
18	10859413	MNGP EPU Steam Dryer Acoustic Monitoring	No	Only related to EPU
19	11133877	EPU Removal of Drywell Bricks in Bioshield	No	Only related to EPU
20	11133856	EPU Feedwater Flow Transmitters/Programmable Control In	No	Only related to EPU
21	11133931	EPU Drywell Spray Flow Valve Replacement	No	Only related to EPU
22	11286981	MNGP EPU Main Steam Drain Tank Modifications	No	Only related to EPU
23	11398720	Engineering & Supervision for EPU	No	Only related to EPU
24	11776513	EPU Steam Dryer Instrumentation Removal	No	Only related to EPU
25	11536446 / +5 11636xxx wo's + 11775097	MNGP EPU License Development	No	Only related to EPU
	LCM Work with some incremental EPU costs (e.g. equipment changes)			
26	10943007	MNGP EPU Main Power Transformer	Yes	The equipment needed to be replaced due to obsolescence. The insulation was at end of life and it was necessary to replace as scheduled to ensure safe operation of plant - end of life issue. The replacement equipment was larger for EPU.
27	10943052 & 11845189	MNGP EPU Condensate Impeller/Pumps/Motors	See below	
27a		EPU only - pumps	Pumps - no	Only related to EPU. Not end of life; possible that pumps would not need to be replaced during plant life.
27b		LCM only - motors	Motors - Yes	The equipment needed to be replaced due to obsolescence. The Consensate pump motors were supplied by GE as part of original plant equipment. A similar size spare motor was purchased from Siemans in 1995 as a rotating spare. During the 1996 rerate new Johnson pumps were procured to increase margin for rerate. In 1997 a second Siemans motor was purchased as one of the GE motors could not be cost effectively rebuilt. At this point we had two Siemans motors and one rotating spare, the remaining GE motor. The performance of the pump/motor combination continued to decline due to service related degradation and was approaching the point where adequate suction flow/pressure could not be provided to the reactor feedwater pumps. Ultimately, these pumps/motors would require replacement to address the low margin for adequate feedpump suction. Therefore, it was necessary to replace as scheduled to ensure reliable operation of plant - end of life issue.
28	11133705	EPU Condensate Demineralizer System Replacement	See below	
28a		Replace 5 vessels & related piping	No	25% of the modification cost related to the larger equipment.
28b		Control systems & valves w/h needed replacemt	Yes - remainder	The equipment needed to be replaced due to obsolescence. Control system, wiring, valves and piping were all at end of life. It was necessary to replace as scheduled to ensure safe, reliable operation of plant - end of life issue. With the existing system manual operation was required with a potential for error to create a chemistry excursion.
29	11133713	EPU Cross Around Relief Valves Replacement	Yes	The CARVs were in service for 40 years which is their design life. Periodic (one CARV each outage) as found testing and repair maintenance was done to maintain the material condition of the valves consistent with insurer's requirements. The only driver to replacement was end of design life and EPU requirement for higher capacity valves. It is not known if replacement would have been required without EPU. In one instance, substantial maintenance was required before returning one valve to service.

Monticello LCM/EPU Work Orders - Description of why work was unavoidable LCM vs. avoidable EPU

	LCM-only work - not avoidable in the absence of an uprate		Equipment needed without EPU?	Reason for unavoidable LCM work, if not avoidable EPU work
30	11133871	EPU Main Steam Isolation Valve Solenoid Valve Replacement	Yes	The equipment needed to be replaced due to obsolescence. Replacement also improved safety margin by providing a solenoid valve that could operate with lower differential pressure between air supply and primary containment conditions. The original design had low margin and replacement was required to improve plant safety for postulated accidents to insure MSIV reliability. EPU reduced margins slightly due to a small increase in primary containment pressure during an accident and, therefore, it was appropriate to address as part of the EPU project to meet project goals related to margin maintenance.
31	11286955	MNGP EPU Replacement of Reactor Feedwater Pumps/Motors	Yes	It was necessary to replace as scheduled to ensure safe operation of plant through end of life. The existing motors were operating into their Service Factor rating such that they were nearing end of operational life for reliable service. The larger equipment and corresponding difficult installation is related to EPU.
32	11286961 & 11757884	MNGP EPU Replacement of 14 and 15 A/B Feedwater Heaters	Yes	It was necessary to replace as scheduled to ensure reliable operation of plant - end of life issue. Tube failures had already occurred to the extent that further plugging would have affected generation and possibly could have put plant operation in jeapordy. The larger equipment was needed for EPU; $6 million in costs related to reinforced floor relates solely to EPU.
33	11286992	MNGP EPU Reactor Water Clean Up Capacity Improvement	Yes	The equipment needed to be replaced due to obsolescence. It was necessary to replace as scheduled to ensure safe operation of plant - end of life issue. The larger equipment was required for EPU. This work was necessary to provide margin to improve water quality for protection of reactor internals.
34	11335729	MNGP EPU Turbine Generator Vibration	Yes	This equipment needed to be replaced due to obsolescence. The existing system was not capable of effectively monitoring turbine system to ensure safe/reliable operation of the turbine. The equipment required to support EPU requirements was more comprehensive in its coverage of the turbine system and more in line with today's large turbine vibration monitoring systems.
35	11410738	MNGP EPU PCT Vent & Purge Valves	Yes	The equipment needed to be replaced due to obsolescence. It was necessary to replace as scheduled to ensure reliable operation of plant - end of life issue. Appendix R cable additional for EPU to address MSO issue.
36	11638897 & 11842626	MNGP EPU 13 A/B Feedwater Heater Replacements	Yes	The existing 13 FWHs were installed in 1983. From a LCM perspective, it was known that at some point during the period of extended operation of the Plant, they would require replacement. Replacement of these heaters was pulled forward since EPU required larger sized heaters to maintain margins. The replacement heaters were not only larger but larger drain piping was required due to EPU. We estimate $8 million for tank drains.

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☐ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	124
Requestor:	Nancy Campbell/Chris Shaw		
Date Received:	May 5, 2014		

Question:

Referring to the LCM/EPU Split table shown on Exhibit TJO-1, Schedule 29, page 4 of 6 through 6 of 6, please provide:

a) the detailed analysis Xcel used to develop the split between Unavoidable LCM Cost and Avoidable EPU cost for each modification;

b) the basis for the conclusion for each piece of equipment that Xcel determined would need replacement to ensure continued operation through the operating license term; and

c) explain what alternatives to replacement Xcel considered. For example, did Xcel consider recoating the condensate demineralizer tanks rather than replacement?

Response:

a) Our ongoing effort to maintain the original equipment at Monticello during its initial 40-year operating license meant that much of that equipment was worn and in some cases obsolete as we approached the decision to seek a license extension. When the Company was granted an extension of its operating license, we recognized that there were significant capital projects that needed to be done to ensure continued safe and reliable operations through the extended license period. Replacement of worn and obsolete systems was required regardless of whether we pursued the uprate.

As described in our October 18, 2013 filing, the Company decided to design and implement the LCM and EPU upgrades to the plant at the same time, so we

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combined these activities into a single Program. *See* Timothy J. O'Connor Direct Testimony, pp. 8, 145. As a result of this combined approach, the Company did not maintain separate accounting or records during implementation for potentially avoidable EPU upgrades as distinct from unavoidable LCM replacements.

When the Company decided to pursue the uprate we also recognized that there would be overlap in the work needed to accommodate the uprate and to support the long-term viability of the plant as a whole. By completing the EPU and LCM efforts simultaneously, the Company hoped to achieve economies of scale and to make the installation effort more seamless as combining the work reduced the expected aggregate duration of outages. While this approach may have resulted in replacing a number of components somewhat ahead of schedule, in the long-term this was a more efficient way to proceed overall. The combination of activities also allowed us to maximize the depreciation schedule and phase in the significant LCM expenses on a schedule that maximized our depreciation of costs over a longer period while minimizing the risk of needing to make major investments or face premature shutdown later in the plant's extended life. As such we continue to view the Project as an integrated effort that is not easily separable.

Because parties had expressed concerns with the lack of any quantifiable EPU amount in prior cases, in preparation for our filing in this case, the Company undertook an analysis to estimate the amount of costs that could have been avoided but for the EPU (avoidable EPU) and those that were necessary to support long-term operations of the plant regardless of whether the Company pursued the uprate (unavoidable LCM). *See* Timothy J. O'Connor Direct Testimony, Schedules 29 and 30.[1] As described in Schedule 29, the analysis we conducted was undertaken after the work was completed and was based on information we knew following completion of the work, including the condition of components found during the Program. Schedule 29 (as updated in Information Response DOC-123) describes the process we went through to analyze the modifications to assess the difference between the avoidable EPU and unavoidable LCM work.[2]

[1] We supplemented that analysis in response to DOC IR-58 and provided an updated Schedule 29 in response to DOC IR-123.

[2] We began by reviewing the cost incurred for each modification. With the total cost for each work order, we then undertook an analysis of how the cost could reasonably be allocated between necessary LCM work and avoidable EPU work. Once that allocation was made, we then allocated the common costs attributable to each modification on a pro rata basis to the LCM and EPU categories.

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For each modification, Company engineers analyzed: (i) the need for the work to support long-term operations; (ii) the need to increase the size or capacity of the modification to support the uprate; (iii) the actual work performed on the modifications, and (iv) the cost of components installed at the plant. Our engineers then assessed whether each modification would have been needed without the uprate. They applied their collective engineering judgment in classifying the work.

- Unavoidable LCM: Some of the modifications (*i.e.*, lines 1-17 of O'Connor Schedule 30, as supplemented in response to Information Request DOC-58) constitute LCM costs as these modifications were ultimately unavoidable, regardless whether we pursued the uprate. These projects were initially determined through analysis of equipment condition and our determination whether the equipment would support operations through 2030. If it was or would no longer be safe or economical to maintain the equipment for the duration of the extended license, the Company's decision to replace it was classified as unavoidable LCM.

- Avoidable EPU: Some of the modifications (*i.e.*, lines 18-25 of O'Connor Schedule 30, as supplemented in response to DOC-58) were determined to be undertaken exclusively for the EPU. In other words, these modifications would not have been done without the uprate. Generally, those costs relate to licensing and a number of modifications, such as the acoustic monitoring, that would not have been needed without the uprate.

- LCM/EPU Combination: Some of the modifications (*i.e.*, lines 26-36 of O'Connor Schedule 30, as supplemented in response to DOC-58), were made for a combination of reasons. Essentially, these modifications needed to be replaced because of age or condition for LCM purposes but required larger systems to accommodate the higher capacity from the uprate. Our engineers reviewed each such modification and made a reasonable engineering judgment of how to apportion the overall cost of the modification between the LCM and EPU aspects. Some of these modifications required up-sized equipment to support higher flows and temperatures associated with the uprate. If we could not determine an independent basis for the cost of the equipment, we attributed 12.1% of the equipment cost to the EPU. Our responses to Information Request

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DOC-74 and DOC-111 provide additional discussion on the reason for apportioning the cost of larger equipment.

b) One or more of the following four considerations influenced our decision whether a piece of equipment/modification: (1) should be replaced or repaired; and (2) should be categorized as unavoidable LCM, avoidable EPU, or a combination of the two.

1. End-of-Life – Was the component/equipment at the end of its design life and would continued operation challenge safe and reliable plant operation? Equipment that is at or near the end of its useful life will need to be addressed to support operations through 2030.

2. Service-Related Degradation – Was the component/equipment showing signs of performance degradation to the extent that a maintenance solution was no longer viable for the long term? If equipment showed signs of degradation, through testing or reduction in performance, that equipment would need to be addressed. While repair can be appropriate, replacement is generally preferable to support extended operations for approximately 20 years.

3. Obsolescence/Modernization – Was the component/equipment no longer supported by its vendor/OEM and/or spare parts sufficiently available to ensure reliable operation? We also considered industry modernization that was taking place to assess whether or not it would have been reasonable to attempt an additional 20 years of operations with outdated equipment. These considerations helped us assess whether repair was feasible or would require custom fabrication and other expensive workarounds, or whether improvements in technology warranted replacement.

4. Design/Operating Margin – Was either the design or operating margin such that the component/equipment represented a threat to safe, reliable operation going forward and for the long-term? We found this factor to be helpful in assessing whether a modification could have been avoided through maintenance.

Our analysis and assessment of these four factors, and the answers stemming from asking ourselves the questions presented above for each of the modifications significantly influenced whether the modification was considered unavoidable LCM work, avoidable EPU work, or a combination

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of the two. As requested, we provide the following additional discussion about our decision-making process as it pertains to the modifications identified on pages 4-6 of Schedule 29 to the Direct Testimony of Mr. O'Connor (as updated by the Company's response to Information Request DOC-123). Please also see our responses to DOC-58 and DOC-123 for additional discussion on this topic.

Condensate Demineralizer

The main criteria driving our decision to replace the condensate demineralizer system were (1) obsolescence, and (2) improving the design to increase reliability by automating the function. The condensate demineralizer system work required replacement of the old analog control system to automate the functions for long-term operations. The old controllers were obsolete and needed to be modernized for the long-term benefit of the plant. The need to upgrade and replace the controller was part of our long-range plan and was a project that had been identified as necessary, separate from the EPU.

Many parts on the old control system were obsolete. The flow controllers were pneumatic and no longer available. The control for the system was a stepping switch, and that was also no longer available. The plant was able to keep the system running, but spare parts for some items were no longer available. The aggregate issues with the system would have led to replacement of the majority of the system and major maintenance to recoat the tanks, if determined feasible, at some point in the period of extended operations, most likely sooner than later.

Once we decided to replace the controllers, this necessitated replacing all of the wiring, piping and associated systems. Similar to the PRNM system (discussed below), any decision to replace part of an analog system with a digital system requires a complete system replacement due to the difficulty in interfacing an analog component to a digital component.[3] We further discovered that the wiring had substantially degraded and needed to be replaced regardless of the other circumstances.

[3] This necessitated the following LCM work to complete the new Siemens/Moore APACS system:

1. Remove numerous instruments and controls (electrical and pneumatic) from panel C-80 and in each of the demineralizer vaults. Controllers, switches, and indication will be replaced with 2 redundant graphical operator display consoles, consistent with installation at many other nuclear plants.
2. Install ~ 40 new electronic flow, pressure, and dp transmitters as inputs to the new system.
3. Design, fabricate, and test the complete waterworks system.
4. As part of the panel replacement, a portion of the wiring was going to be re-used, but was found to be too deteriorated and was also replaced.
5. Other components that were becoming obsolete with parts no longer available were the ball valves, pneumatic valve positioners, and holding pumps.

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As part of our desire to enhance reliability, we also considered the need to modernize and upgrade the design of the system to automate the demineralization process to minimize the risk of human error. The old system required multiple valve manipulations to be performed manually while the new system automated and repositioned the system components to reduce the potential for error. Part of the new system was a different backwash process that improved reliability of operations of the plant. The automation of this system required replacement the existing piping and installation of new vessels.[4] All of this work was LCM in character and needed to be completed to support operations to 2030 regardless whether we pursued the uprate.

The only aspect of this project that was related to the EPU was the need to install larger vessels to accommodate the higher flows associated with the increased capacity from the uprate. We considered whether we could repair the existing system by relining the vessels but determined that this would not be sufficient to address all of the issues we encountered with this existing system. Replacing the vessels was much less labor intensive and minimized the amount of radiation dose we encountered compared to what would have occurred had we repaired the existing vessels.[5] Project E-99R000-11 PLC based Condensate Demineralizer System was originally placed on the Long Range Plan in 2000.[6]

This new system is consistent with DFCS design platform. It results in reduced training, spare inventory, and utilizes experience of plant staff. The new system will consist of ~350 digital and ~50 analog inputs and outputs. It also creates

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[4] The existing air operator for the condensate demineralizer bypass valve AO-1740 was not large enough to open the valve on high system differential pressure of 52 psid. A new operator and control arrangement was installed to ensure opening of the valve during high system dP conditions. The CDM bypass valve is required to open in the event of closure of the CDM outlet valves, such as due to loss of instrument air. This ensures a supply of condensate/feedwater to the reactor vessel and reduces reliance on emergency injection systems for some transients.

[5] This is because repairing them would have required working within the existing vessels (an area of higher dose than in the vaults). Also, the liners and components are highly radioactive and it is difficult to contain contamination. Also, access to the area to conduct the repairs is limited and would have required expensive tooling to be developed for this specific application.

[6] The project was re-estimated in 2002 to include replacing the pneumatic flow balance control system, with installation during the 2003 re-fuel outage. The scope of the project was to replace the existing condensate demineralizer backwash and pre-coat system with a PLC based system. The new system would replace obsolescent and more than 30 year-old equipment including: timers, relays, and pnuematic instruments used for flow balance control and in automating the CDM backwash and precoat process. The original system required significant attention of plant staff to regenerate elements and in system maintenance and repair. There was an ever increasing failure rate of these components and this system's continued reliability and availability is critical to daily plant operations.

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substantial saving in element replacement costs and resin costs, particularly if it had not been done in order to match EPU flow conditions. Also, the upgrade improved water quality, which will reduce radiation dose for plant maintenance. The use of the programmable logic controller (PLC) has resulted in reduced operator time to backwash and precoat CDM vessels as well as reduced isolation and testing time associated with less maintenance.

Consideration of the age of the existing condensate demineralizer and the need to modernize this equipment led us to replace rather than repair this existing system for the long-term benefit of the plant. However, the new system also included larger vessels to accommodate greater flow that will be encountered under uprate conditions. As a result, we allocated an appropriate amount of the overall cost of this modification to the EPU as reflected in O'Connor Schedule 30, as supplemented in response to DOC-58, line 28.

Feedwater Heaters
Service-related degradation was the primary consideration in our decision to replace rather than repair the six feedwater heaters that were part of the Program. In addition, four of the six replaced feedwater heaters were original plant equipment and the other two were 30 years old. They had all reached the end of their realistic useful life.

We conducted tests on the feedwater heaters and determined that the tubes within the heat exchangers were experiencing plugging. This phenomenon is normal in the life-cycle of heat exchanges and becomes a problem only if a sufficient amount of the tubes have become plugged that it degrades performance. The 14 A/B and 15 A/B feedwater heaters were original 40-year-old equipment and the 13 A/B feedwater heaters were 30-year-old equipment. Our testing showed that they had degraded to the point where further tube plugging was not a viable long-term option. As a result, it they needed to be replaced to support extended operations if an extended operating license was obtained.

A related consideration supporting our decision is the end-of-life criterion because of the age of the feedwater heaters that we replaced. The feedwater heaters and associated equipment were recognized to be older equipment that would need to be replaced to support extended operations in our 2003 capital projects summary sheet. We provide a copy of the 2003 capital projects summary sheet as Attachment A to this response that addresses this need. As described in Mr. O'Connor's Direct Testimony (p. 38) our experience was that

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we had maintained the existing feedwater heaters well and made them last longer than experienced in the industry. Ironically, the good job we did in maintaining these heaters longer than our peers meant that they were quickly reaching the end of their useful life, as demonstrated by the testing that showed excessive tube plugging. Thus, it is clear that we would need to replace this equipment to support operations to 2030, regardless of the uprate.

Moreover, the Company recognized that further repair of this system would not be sufficient and that replacement was in the best interest of the plant. Substantial maintenance requiring longer refueling outages to re-tube the heat exchangers was not desirable even without EPU required capacity change.

Nevertheless, the feedwater heater work required installation of larger equipment to accommodate increased flows associated with the uprate. Thus, we took that allocation into account and attributed costs to the EPU. See O'Connor Schedule 30, as supplemented in response to DOC-58, lines 5, 13, 28, 29, 32, 34, and 36.

Reactor Feed Pumps and Motors

The decision, to replace the reactor feed pumps and motors, was driven by service-related degradation issues and obsolescence.

The main criterion supporting replacement of these pumps and motors (regardless of the uprate) is that they had experienced chronic performance problems that could be addressed by replacing them with modern equipment. The original reactor feedwater pumps were a custom redesign of a 3-stage fire pump into a 2-stage feedwater pump. Our experience with these pumps was that they required frequent overhauls during refueling outages.[7] Maintenance on the original pumps was overdue at the time the decision to replace was made so an overhaul was avoided.

While pumps can and are repaired, the number of times that you can weld and machine the casing without replacing the casing is limited. If the pump casing is at the end of its service life, the most cost-effective option is to replace the pump

[7] The major issue with pump maintenance was that the high differential pressure joint between the pump casing and the impeller barrel assembly has had a problem with cutting by water leaking by the joint. This leakage can occur over time between maintenance cycles. Repair has required machining of the pump casing to remove the cuts since weld repair is not feasible. This repair also requires obtaining a barrel assembly that is increased in length to accommodate the material removed from the casing by machining. This repair is difficult to accomplish in the time frame of a refueling outage and can lead to challenging outage length which supported pump replacement. Maintenance on the original pumps was overdue at the time the decision to replace was made so an overhaul was avoided.

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assembly. We believed that we would face that situation in the next several cycles (approximately six years) and as a result determined it was prudent to accelerate and integrate replacement of the pumps into the EPU design.

A second criterion supporting replacement was obsolescence, as the pumps age, the pumps became harder and took longer to repair and we became concerned that these performance issues would result in longer outages as we tried to obtain hard-to-find spare parts.

With respect to the pump motors, these were original equipment that was experiencing performance degradation that required replacement. While the rotating assemblies had been replaced the stators, were still original. Given their age, the motors were not designed or expected to remain in-service until 2030, approximately 60 years on a nominally 40-year life. Service life is defined based on motor insulations class within the industry standard NEMA MG-1 Motors and Generators. We had evaluated the acceptability of these motors beyond 40 years using NEMA MG-1 standard, and determined that there was a need to replace the motors as part of LCM. This is consistent with the 2003 capital project summary sheet (Attachments B and C to this response), which included replacement for LCM prior to the LCM/EPU Program based on limited remaining operational life of these motors. Note: Attachment B also includes other LCM projects.

Based on these two factors, we would have had to replace these pumps and motors regardless of whether we proceeded with the EPU. We had identified in our 2003 long-range plan that this system was one that was going to need to be replaced to increase plant reliability for the license extension period and that not replacing this component could potentially lead to an extended shutdown, which was an unacceptable risk if the Company was going to seek to extend the license. By the time the EPU began to be considered, we were already in the process of evaluating these pumps and motors to determine what we needed to do to support the life extension. We recognized that they were going to need to be replaced and we anticipated that the replacement would have had to occur in roughly the same timeframe as they were replaced as part of the Program.[8]

[8] As part of the EPU evaluation, we reviewed the recommendation to add a smaller capacity supplemental reactor feed pump and motor. This proposed design presented significant installation and operational challenges as described on pages 124-126 of Mr. O'Connor's Direct Testimony. We also determined that even if we added a supplemental reactor feed pump, the two existing pumps and motors would still require replacement in the near future to support long-term operations. Replacement of the two pumps and motors with two larger ones allowed the plant configuration and operations to remain consistent during the extended life. Reliability has improved by addressing and eliminating wear

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Because the reactor feed pumps and motors replacement was necessary to support long-term operations but also needed to be sized to support uprate conditions, we allocated costs for this modification to both as shown on O'Connor Schedule 30, as supplemented in response to DOC-58, line 31. This is one of the systems where the Company increased the size of the pumps and motors to accommodate the uprate. As a result, we allocated 12.1% of the equipment cost to the EPU to reflect the higher capacity requirements to increase generation by 12.1%.

Condensate Pump and Motor
This project was similar to the reactor feed pumps and motors project described above. It 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. The decision to replace the existing condensate pump and motor were driven primarily by service-related degradation issues and obsolescence considerations.

Regarding service-related degradation, the condensate pump motors were supplied by GE as part of original plant equipment.[9] Performance of the pump/motor combination was degrading and was approaching the point where adequate suction flow/pressure could not be provided to the reactor feedwater pumps. Performance degradation indicated that the pumps needed to be replaced before reaching the end of the period of extended life of the plant.

Regarding obsolescence, the condensate motors were in somewhat better shape and immediate replacement of them was less critical. However, we were concerned about their long-term viability, particularly since we knew we had to replace the related condensate pumps. Because we were already working on the pumps, the addition of motors to assure continued reliable operations was not viewed as being a significant additional cost and was appropriate to uprgrade at that time to assure performance over the extended license life. Further, retaining

conditions that necessitated preventative and corrective maintenance of this equipment to accommodate the new, larger pumps and motors.

[9] A similar size spare motor was purchased from Siemens in 1995 as a rotating spare. During the 1996 rerate, new Johnson pumps were procured to increase margin for the rerate. In 1997, a second Siemens motor was purchased as one of the GE motors could not be cost effectively rebuilt. At this point we had two Siemens motors and one rotating spare, the remaining GE motor.

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the old motors would have required approximately two additional 10 year major bearing replacement preventative maintenance (PM) (removing rotors) if EPU was not pursued. In light of the need to replace the pumps, we concluded it was more appropriate to replace the motors at the same time.

Given their service-related issues and age, these older pumps and motors needed to be replaced, rather than repaired, to support long-term operations but needed to be sized larger to support uprate conditions. We allocated the proportionate cost of the larger equipment to the EPU. As a result, we allocated the costs between LCM and EPU as described in O'Connor Schedule 30, as supplemented in response to DOC-58, line 27.

13.8 kV Distribution System

The decision to add the 13.8 kV System to the existing plant's distribution capacity was driven mainly by the desire to improve the design and increase operating margins as well as obsolescence considerations. We analyzed many options with the existing 4 kV busses or adding new busses at a higher voltage. These additional design requirements were previously provided in an extended discussion of the need for the 13.8 kV System in response to Information Request DOC-83.

First, as to the desire to update the design and increase operating margins, the existing system operating margin was consumed by addition of loads over the 40-year life of the plant. Addition of new distribution capacity (at whatever voltage) was mandatory to recover margin and have reliable safety switchgear and breakers. The breakers were discussed in a 2003 capital project summary sheet as the Company began to explore a license extension. We provide a copy of this document as Attachment D to this response that addresses this need. An example of this was the 4 kV System which had essentially no margin to accommodate additional load. We ultimately concluded that adding busses at 13.8 kV addressed all of the design requirements including the additional capacity for approximately the same investment.[10]

While the design requirements were complex, they were also safer to install in a separate area as a new 13.8 kV System, rather than modify or replace the 4 kV

[10] The 13.8 kV system provided significant improvement in electrical system operating fault margin on bus 11 (from -1% to +43% with EPU loading) over the former 1960's 4 kV system. The existing 4 kV system interrupting fault current would have been exceeded by 1%. The new 13.8 kV system would accommodate new loads with 43% margin to the fault interrupting current rating and with room to grow as additional loads were added.

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System on a piecemeal basis. The 4 kV System consists of 6 busses and 36 cubicles with rotating spare breakers. The existing 4 kV System and room were not designed to facilitate being taken out of service for replacement, because the electrical systems must operate continuously to protect the health and safety of the public at all times.

Busses 11 & 12 were replaced with the 13.8 kV project. The addition of the 13.8 kV busses freed up additional cubicles in addition to 4 kV breakers spares for use in maintaining the remaining 4 kV breakers. The cubicles were experiencing tracking deterioration and if not aligned, this interfered with safe operations. Specifically, if the cubicles are not aligned, it makes it difficult to rack a breaker in and out of its cubicle and potentially could electrically short across the bus. *See* Attachment E to this response, Equipment Improvement Long Range Plan Request (EIR) for Breakers and Switchgear October 23, 2012.

Note that this project also incorporates the attached EIR that was tracked as PRG Log # 2011-008, Protective Relay Replacement 4.16 kV Switchgear. *See* Attachment F to this response. That project had been stand-alone, but was later merged with this project per the PRG meeting minutes from April 9, 2012. The funding for the two portions of this project has been broken out for each portion separately and in total in the Long Range Plan Data section below.

The decision to add new distribution capacity at a different voltage was also influenced by the obsolescence of the 4kV equipment.[11] The 4 kV horizontal, magnablast breakers and switchgear were original design equipment that was obsolete and no longer supported by the vendor. Further, the breakers themselves are no longer available. Spare parts to prolong breaker life are difficult to find.

Finally, when we decided to install the 13.8 kV busses, we needed to replace the 1R and 2R transformers to provide 13.8 kV voltage to the new 13.8 kV busses to feed the reactor feed pump, condensate pumps, and recirculation MG set motors. In addition, the replacement of the 1R and 2R transformers was needed due to aging and operating considerations. We note that these transformers (1R

[11] The 4 kV breakers are horizontal magnablast breakers that are no longer manufactured by GE which has resulted in increasing difficulty in maintenance, reliability, and availability issues with adequate spare parts for rebuild. The four remaining busses and switchgear have been evaluated for LCM options necessary to replace or upgrade some (or all) of the remaining 4 kV busses and breakers at some point in the plant's remaining period of extended operation to ensure safe operation of the plant through the end of life.

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and 2R) are different than the transformer major modification that is discussed below.

The original 2R transformer was a 50 MVA, 3 winding with low voltage Automatic Load tap changers Delta/wye/wye 34.5/4.16/4.16 kV. The 2R transformer was installed in 1985 when the Unit Auxiliary Transformer was replaced.

The original 1R transformer was a 37.3 MVA, 3 winding with fixed tap no auto load tap changing HV's 33,333/37,333 KVA LV's 16,667/18667 KVA wye/wye/wye 115/4.16/4.16 kV. The 1R transformer was of 1967 vintage (47 years old). The original 1R transformer was recognized as a low margin transformer from 1998 re-rate from 1670 MWT to 1775 MWT. Further, the existing 1R transformer did not meet Company standards for operability.

The Company's long range planning prior to developing the LCM/EPU Program included 1R transformer replacement. We provide a copy of this document as Attachment G to this response that addresses this need. The 1R transformer would have had to serve as a reliable source of off-site power to a nuclear plant for 63 years (2030) at the end of plant life, well beyond typical service life. The 1R transformer would likely have had to been replaced for reliability, and nuclear risk mitigation during the remaining plant life as noted in the long-range plan.

The 2R transformer would have been 45 years old in 2030, but since the 2R transformer provides the plant's primary source it is loaded at approximately 50% of rating for nearly 100% of the remaining service life and thus undergoing a shorter service life than the 1R transformer. While neither the 1R nor 2R transformers were experiencing equipment degradation concerns indicative of near term replacements (i.e., approximately 5 year time frame) both transformers would likely have reached a point of operation where there replacement would have been pursued to ensure high reliability of off-site power for the remaining plant operating period.

The 13.8 kV modification is one where we have attributed the work to LCM work (O'Connor Schedule 30, as supplemented in response to DOC-58, line 12). As we considered the long-term viability of the plant we concluded that adding significant distribution capacity upgrades would have been necessary for the plant to remain viable for the extended license period irrespective of the uprate.

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PRNM

This modification included design, engineering, and installation of a GE Nuclear Measurement Analysis and Control power range neutron monitoring system (PRNM) to replace the station's old analog monitoring systems. This modification also included an upgrade of the Plant Process Computer to a state-of-the-art processing system. Each of the four considerations discussed above were part of our decision to replace the existing PRNM system and to categorize the project as unavoidable LCM.

This equipment did not perform well and needed to be replaced. In regards to the service-related degradation, testing showed that the system was experiencing performance-related degradation. In response to a repeated failure of an electrolytic capacitor in a safety-related flow controller, we undertook a major effort to identify those key electronic components susceptible to aging effects. This evaluation was based on EPRI guidelines for managing such effects (TR1008166 Guidelines for the Monitoring of Aging of I&C Electronic Components, October, 2004 and TR1003568 Collected Field Data on Electronic Part Failures and Aging in Nuclear Power Plant I&C Systems, September, 2002).

Related to the design consideration, design deficiencies in the existing system began emerging that caused the site to modify it. For example, the HI-HI Trip APRM output to the Reactor Protection System (RPS) was masked by the INOP output during quarterly system functional testing. While this limitation may have been accepted earlier in plant life, increased emphasis on assuring that all aspects of required surveillance testing be met resulted in the need to modify the flow control trip reference card to allow the HI-HI Trip output to be tested individually.

With regard to end-of-life considerations, the age of several components of the existing PRNM system meant that these components needed to be replaced or repaired to support operations through 2030. Those components identified to be susceptible to one or more of the aging mechanisms were replaced, refurbished, or placed on a PM schedule to manage the effects. This effort was initially known as ARDEC (Age Related Degradation of Electronic Components). It was eventually merged into the PM program. Most ARDEC components were individual circuit boards in transmitters, trip units, power supplies, or alarm circuits. As a result, they could be replaced with spare units which had already been replaced or refurbished and then cycled through the same process refurbishment/replacement process. However, there were a number of systems that contained so many individual electronic components

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susceptible to aging effects that it was impossible to efficiently cycle each subcomponent through such a process while maintaining the operability of the system. Thus, the only feasible solution was a wholesale system replacement.

The nuclear instruments (NI) are examples of just such systems. The NIs are made up of the Startup Range and Power Range instruments which monitor the neutron flux of the core throughout all modes of reactor operation, even when shutdown. This system measures the reactor core parameters and provides the operator information on the operation of the core. A failure of this instrumentation would have potential reactivity impacts. Source Range Monitors (SRMs) and Intermediate Range Monitors (IRMs) are used during shutdown and refueling conditions while the Average Power Range Monitors (APRMs) and Rod Block Monitors (RBMs) are used during power operations (the range of each instrument type overlaps). The original APRM system (including flow converters and transmitters) contained in excess of 170 electronic boards distributed over 8 chassis in 5 panels.

The analog components of the APRMs and RBMs are what were replaced in 2009 under the power range neutron monitoring system. Since these components are required to monitor the core parameters during power operations, they could only be replaced wholesale during a refueling outage.

For the obsolescence criterion, the prior system was an analog system that presented several operational and practical issues. Due to its age, we had for some time had difficulty in obtaining replacement equipment. For instance, obtaining replacement parts for the APRMs and RBMs had already become an issue. Moreover, General Electric – Hitachi's (GEH) was not expected to support this old analog technology for much longer because GEH replacement system is a digital system that had been designed for and installed at 22 other sites prior to Monticello. These new digital parts and equipment are incompatible with the existing analog system and cannot be used to repair or replaced analog components.

In addition to alleviating the aging electronic component issue, replacement provided a number of improvements making the system more reliable and easier to maintain. For example, while the quarterly calibration of the flow instrumentation associated with the original analog system required the plant to be in a risky ½ SCRAM condition for two 8-hour days, the calibration requirement of the digital systems flow components was reduced to bi-annually and did not require ½ SCRAM conditions. Similarly, while the every-2000-

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operating-hours calibration of the LPRMs required operators or reactor engineers to tweak a potentiometer on each of the 96 LPRM cards, the digital system calculates the new gain values with the help of the plant process computer and, once validated by the operator, gets automatically updated with the push of a button. As such, both the cost of maintaining the system and the risk associated with performing the required testing of the system decreased substantially.

A consideration of the four factors resulted in our determination that replacement, rather than repair, of the PRNM was needed to support continued operation of the plant through the period of extended operation regardless of energy/capacity output. Thus, we categorized the project as unavoidable LCM. *See* O'Connor Schedule 30, as supplemented by our response to DOC-58, line 1.

HP Turbine Replacement

Xcel Energy had replaced the HP turbine at Monticello in 1996 (after 25 years of operation) with major recalibration in 1998. Our nuclear insurer (NEIL) requires that our turbines be inspected and overhauled approximately every 10 years. This requires dismantling the turbine, preparing a detailed assessment, repairing or replacing components, and bringing the turbine back to 'like-new' condition. After the major recalibration in 1998, the next major overhaul was scheduled for the 2009 outage (consistent with our NEIL obligations).

As it relates to the four categories mentioned above, there are two primary reasons we concluded the HP turbine should be replaced, rather than repaired, as part of the LCM/EPU Program. First, we recognized the existing HP turbine would present end-of-life considerations during the extended life of the Monticello plant. The first turbine lasted 25 years, and we did not find that the current turbine would last 35 years, regardless of the uprate. While it was not worn out yet, we recognized it needed to be replaced ultimately to support the plant to 2030 and concluded it was better to accelerate that replacement to maximize the value of the equipment and spread its cost over the remaining life of the plant. We note that, industry experience has shown that these types of turbines age, they need more frequent repair for cracked blades and ultimately require replacement. Partial replacement of the blades is not the preferred repair path because it could lead to vibration and imbalance conditions due to mixing old and new blades. In addition, the mixed blades could impact steam flow efficiency. Thus, in light of this conclusion that the turbine would reach the end of its useful life prior to expiration of the extended operating license, we planned

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for this work in the 2009 outage as that replacement could be undertaken in lieu of the required major overhaul.

The second reason for replacement (rather than repair) related to the obsolescence of the existing turbine and the need to modernize this equipment to improve reliability and efficiency. Since 1996 when the existing turbine was placed in-service, GE has made major advancements in turbine design. Replacing the existing HP turbine with a turbine with an Advance Vortex design provides superior reduction on secondary losses and profile losses. This is due to the new design providing efficiencies across the turbine which reduced steam flow losses, thus resulting in greater steam flow. The Advance Vortex design also incorporates a monoblock rotor design which is not prone to blade or rotor failures, and thus improves the reliability of the turbine. Finally, the Advance Vortex design incorporates the latest modern manufacturing technique to improve the quality and consistency of manufacturing vanes which is the bases of the Advanced Design Steam Path (ADSP).

System performance considerations also impacted our decision to replace the HP turbine. For a number of years we experienced about 5 mil of vibration on the turbine floor from an unknown source in the rotating elements of the turbine. This raised a serious concern that the vibration could result in fatigue failure if this vibration continued over the long term. We had worked to resolve the vibration but were unable to do so. Our engineers believed that the cause of this vibration was the existing HP turbine. Since the HP turbine has been replaced, the vibration has ceased.

As it pertains to our allocation between LCM and EPU, even though the new HP turbine was sized to support additional steam flows, we were able to determine that the cost of the replacement turbine was comparable whether or not the EPU was undertaken. As a result, we attributed the cost of the turbine itself as unavoidable LCM. *See* O'Connor Schedule 30, as supplemented by our response to DOC-58, line 4. We note that this modification included the installation of a new vibration monitoring system, which was complicated by the EPU. *See* O'Connor Schedule 30, as supplemented by our response to DOC-58, line 34. Thus, we allocated the costs for the installation of the new vibration monitoring system to the EPU. Note that Schedule 29 of Mr. O'Connor's testimony contained an error in the chart describing the HP turbine. This was corrected in our response to DOC-123 which provides a corrected Schedule 29.

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Steam Dryer

As it related to the four categories outlined above, there are two primary reasons we concluded the steam dryer should be classified unavoidable LCM regardless whether the uprate had been pursued: (1) service-related degradation; and (2) design/operating margin. While we acknowledge the steam dryer was an important component of the NRC's analysis in deciding whether to grant our EPU license, we conclude that the steam dryer would have needed to be replaced prior to 2030 regardless of the uprate. As a result, based on our avoidable EPU versus unavoidable LCM analysis, we concluded that the steam dryer replacement is most appropriately categorized as unavoidable LCM.

The critical factor that lead us to classify this modification as unavoidable LCM was service-related degradation considerations with the existing steam dryer. We provide an extensive discussion of the need to replace the steam dryer to support long-term operations in response to Information Request DOC-72. As described in more detail in that answer, the original steam dryer was designed in the mid-1960s. Over time, its operability decreased and we believe the steam dryer could not have been maintained through 2030 whether or not we pursued the uprate.

The steam dryer was experiencing performance issues and continuing performance-related degradation such that the critical factor performance of this equipment was marginally acceptable at the time we began planning for the LCM/EPU Program. An example of a performance-related degradation that supported our decision was the original steam dryer's inability to maintain Moisture Carryover (MCO) levels.[12] *See* Attachment H to this response. The most significant impacts of the MCO are on flow-accelerated corrosion and shutdown radiation levels. Both are impacts on maintenance. Increase in corrosion adds to wear on steam related components such as the turbine. An increase in radiation levels makes maintenance activities more difficult and costly.[13] The new steam dryer is operating with MCO levels that are a factor of

[12] The original steam dryer was designed to maintain MCO to 0.1% or below. While the original steam dryer typically stayed near this original MCO design level, some operation above this level did occur. For instance, in 2009, levels reached 0.11%. Further, the original steam dryer had three cracks with two being due to fatigue failure and one from intergranular stress corrosion cracking. Stress analysis for evaluation of acoustic loads on the original steam dryer were pursued based on feedback from our vendor that was expected to be able to evaluate the dryer with no need for physical modifications. Physical modifications were possible but would be extremely radiation dose intensive and would be costly to analyze and install.

[13] Both had been evaluated for increasing MCO from 0.1% to 0.5%. It was predicted that shutdown radiation levels of certain components would increase by a factor of up to 11.3. These issues would have increased maintenance costs if not corrected.

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10 or more below the design MCO value of 0.1% which will reduce future maintenance costs.

Also related to the service-degradation criterion, was the fact that repairing the old steam dryer would have been expensive due to the very radiation dose intensive nature of the work related to such a repair. The existing GE dryer was in-service for 40 years and thus had become irradiated.

From a risk-management perspective, another area of concern was the prescriptive requirements imposed by the BWR Vessel Internals Program (BWRVIP) for inspection of vessel internals. These requirements were targeted at old steam dryers like the one at Monticello. This program requires that we comply with any recommendations arising out of the inspection or submit an explanation to the BWRVIP executive committee. Further, the results of the inspection are reported directly to the NRC. After an issue is reported, the NRC will require corrective actions with industry-wide applicability. The new steam dryer installed at Monticello is the first of its kind in the United States. As a result, the only time that an issue would be reported to the NRC that would require corrective actions would be related to our specific equipment rather than being subject to issues related to all aging vessel internals. In contrast, if an issue came up related to the old steam dryer vessel internals or those at any other plant, this would be subject to NRC mandated corrective actions. This raised the risk of extended outage if we were required to replace the old dryer and prohibited from operating until it had been replaced. This risk existed regardless of whether we pursued the EPU.

Due to the service-related and design/operating consideration, this modification is one where we have attributed the work to LCM work (O'Connor Schedule 30, as supplemented in response to DOC-58, lines 10, 11, 18, and 24). As we considered the long-term viability of the plant we concluded that replacing the steam dryer would have been necessary for the plant to remain viable for the extended license period irrespective of the uprate and in late 2007, GE recommended we replace, rather than modify the existing steam dryer.

Transformers
End-of-life considerations were the primary factor that drove our decision to replace, rather than repair, the original main GSU and 1AR transformers, which were 40-year-old and 60-year-old, respectively. Evaluation by Xcel Energy

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Transmission and Distribution transformer expert concluded replacement was required for both the main GSU and 1AR transformers as they were nearing end of life due to insulation degradation. Both of these transformers were identified for replacement in the 2003 capital projects summary sheet. We provide a copy of the capital projects summary sheet from 2003 as Attachment G to this response that addresses this need. Additionally, on the GSU main transformer, we had received a significant operating experience report from INPO, requiring that we inspect the GSU transformer because industry experience showed it was a vulnerable system and to replace it as necessary. This all led us to conclude that the transformers would need to be replaced regardless of the uprate and replacing this system soon was in the best interest of the plant.

A second factor that supported replacement of these transformers was performance degradation considerations. Through transformer monitoring, via oil analysis, we determined that there was a gassing problem with the GSU transformer that was resulting in transformer degradation within the transformer that potentially could lead to in-service failure. See Attachment I to this response. Replacement of the GSU transformer was the best option to correct this gassing issue.

The replacement of the 1AR transformer is one where we have attributed the work to LCM work (O'Connor Schedule 30, as supplemented in response to DOC-58, line 17). As we considered the long-term viability of the plant, we concluded that replacing this system would have been necessary for the plant to remain viable for the extended license period irrespective of the uprate. By contrast, the main transformer is allocated between LCM and EPU (O'Connor Schedule 30, as supplemented in response to DOC-58, line 26) since we needed to replace the GSU but recognize that we did so with a larger one to accommodate the increased energy production from the uprate.

Licensing
The licensing effort to obtain the EPU was allocated solely to the EPU as described in Schedule 30, line 25, as supplemented by our response to DOC-58. Note that Schedule 29 of Mr. O'Connor's testimony contained an error in the chart describing the Licensing. This was corrected in our response to DOC-123 which provides a corrected Schedule 29.

Other Modifications
As described in Schedule 29 and 30 (as supplemented by our response to DOC-58, there were a series of smaller projects (17 Child Work Orders) for other

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smaller projects, totaling about $34.6 million or about 5% of the overall Program total. We provide the following discussion about selected projects within this category. Note that Schedule 29 of Mr. O'Connor's testimony contained an error in the chart describing the Other Modifications category. This was corrected in our response to DOC-123 which provides a corrected Schedule 29.

Additional EPU Projects
We undertook a number of other projects that were specifically needed as part of the uprate. These projects are shown on O'Connor Schedule 30 (as updated by our response to DOC-58) lines 19, 20, 21, 22, 23, and 24. All of these projects were undertaken specifically to address the increased capacity, flow and heat associated with the uprate. Attachment J to this response is a 2003 capital project summary sheet related to EPU projects.

Additional LCM Projects
We undertook a number of other projects that were specifically needed as part of the plant's life-cycle maintenance program. These projects are shown on O'Connor Schedule 30 (as updated by our response to DOC-58 lines 2, 3, 6, 7, 8, 9, 14, 15, and 16). All of these projects were undertaken to address specific issues that needed to be dealt with to facilitate the long-term operations of the plant. The descriptions in Schedule 30 (as supplemented by our response to DOC-58), provides the rationale for all of these projects. *See* Attachment K to this response.

Generator Rewind
Line items 14, 15, and 16 of O'Connor Schedule 30 (as supplemented by our response to DOC-58), addresses our project to rewind the generator at Monticello.

As it relates to the four criterions as outlined above, the generator rewind was driven by considerations related to the end-of-life and service-related degradation considerations of the existing generator.

With regard to end-of-life considerations, in our 2003 evaluation of the plant in support of our license extension analysis, we recognized that the existing generator was original equipment and needed significant work to support long-term operations at the plant. We also note that, when we moved the old rotor to Chicago after its removal, we had the contractor conduct a test of its performance ability. The equipment failed that test, meaning it was at the end of

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its useful life and was near the stage where it would have failed had we left it in place.

We considered replacing the generator entirely because it was over forty years old and nearing end of life. However, on further analysis, we concluded that major components of the generator were still viable and that rewinding the insulation within the generator was sufficient to bring the equipment to adequate operating standards for the long-term. The Company has significant experience with rewinding generators as this is a common repair needed for older generators and we were confident that this action would support continued operations.

Along with the generator rewind, the Company replaced the exciter as it had reached its end of life and was showing service related degradation. The Company evaluated replacement with a static exciter but a like-for-like replacement was determined to be the most cost effective.

The original exciter was capable of supporting plant operation at EPU power levels however GE recommended that the exciter be replaced in any event to ensure reliable operation over the next 20 years of plant operation due to its age. The original exciter was original plant equipment and therefore had been in service since 1971, or approximately 40 years when it was replaced; thus it was at or beyond the expected designed service life. A 2003 capital project summary sheet for the exciter is provided as Attachment L to this response. The following issues had to be considered for a 40 year old exciter:

a. Condition of stator insulation and winding support components
b. Field winding issues (distortion, fatigue, etc)
c. Condition of the cooling water tubes in the air cooling section
d. Condition of misc components (collector ring, control wiring and associated components, etc)
e. The exciter had experienced elevated vibrations (bearing and structural) over most of its life

We did investigate static excitation systems as a potential replacement for the exciter. Significant challenges were identified and it was concluded that installing a static excitation system was possible but would be unduly expensive. As a result, Company personnel concurred that it was prudent to replace the exciter and made the decision to install a replacement like for like rotating exciter.

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The decision to replace the stator water cooling was based on design and service-related degradation considerations. On the design front, replacing the stator water cooling resolved a single point vulnerability that we were experiencing with the existing system. The replacement system provides for a second heat exchanger in the event a leak was to occur in the first one, thereby creating redundancy and increased reliability. Also, replacement addressed tube degradation issues related to the original stator water cooling equipment.

End-of-life and service-related degradation considerations drove the decision to rewind the generator and replace the static exciter, the stator water cooling equipment. In regard to allocating these costs, we attributed these modifications to LCM as, shown on Schedule 30, as supplemented in response to DOC-58, lines 14, 15, and 16, because the generator was already sized sufficient to support operations at the increased capacity associated with the uprate. As a result, we did not do any additional work on this modification beyond what was necessary for life cycle management purposes.

Additional Combination Projects
We undertook a number of smaller projects that were combination projects that addressed aging equipment that needed to be upsized to address the uprate. These projects are shown on O'Connor Schedule 30 (as updated by our response to DOC-58, lines 30, 33, and 35). All of these projects were undertaken to address specific issues that needed to be dealt with to facilitate both the long-term operations of the plant as well as to address the additional flow/heat/capacity necessary for the uprate. Our descriptions in Schedule 30 (as supplemented by our response to DOC-58), provides the rationale for all of these projects.

In addition, we provide the additional discussion about line-item number 30 relating to the Cross-Around Relief Valve ("CARV"). 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.

The CARV replacement was somewhat complicated due to the fact that high radiation levels during plant operation prevented the ability to inspect the as-built system installed configuration prior to the 2009 outage. This was a consequence of the decision to move forward on parallel paths to make resources available to

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our customers as soon as possible. Therefore, adjustments to the piping and pipe support design had to be made during installation.

c) In response to subpart (a) and (b) above, we describe our decision to replace or repair each particular piece of equipment. Specifically to the example raised in this question, please see our discussion in part (b) above on the condensate demineralizer replacement and our consideration of relining the vessels and why we chose the replacement option.

Attachments E and F are marked "Non-Public" in their entirety as they contain confidential security data that the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). Due to security information policies and concerns, the information provided in this response has been marked Non-Public. The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp. 3.

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XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Replace Feedwater Heaters		Monticello NGP		
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply - NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW					
ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$ 1,000,000	$ 1,000,000	$ 2,000,000	$2,000,000

DESCRIPTION:
Service life of feedwater heaters requires they be replaced to support the extended period of operation. There are 5 heaters in each of two trains of feedwater.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability and efficiency for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

Annual General Capital Requirements

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Capital Projects <$1M		Monticello NGP		
OPERATING CO.	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	Annually			
	$0	$ 7,000,000	-	-	-

DESCRIPTION:
Example of annual capital projects are: Feed Pump Motor and Pump Replacement, Cooling Tower Repair, Replace Drywell coolers, CRD Stub tube UT inspection for IGSCC in HAZ of housing-to-stub tube welds, refurbish the recirculation suction and discharge valves and replace stems, replace RPV closure stud bolts refurbish, replace internals of the SRVs, implement long term plans for safe end weld overlays or replacement, replace refueling and seal bellows carbon steel components, replace the recirculation pump shafts, impellers, motors, replace and upgrade battery cells, and refurbish RWCU pumps, motors and Hx.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Feedwater & Main Steam Pipe Replacement	Monticello NGP		

OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$ 500,000	$1,500,000	$1,000,000	$500,000

DESCRIPTION:
Replace portions of feedwater and main steam pipe that are susceptible to erosion and corrosion.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability and safety for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
4KV Breaker Replacement		Monticello NGP		
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	IDF/ BU Number
Energy Supply – NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$5,000,000	-	-	$5,000,000

DESCRIPTION:
Replace 4 KV breakers due to aging and wear.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

PUBLIC DOCUMENT:
TRADE SECRET INFORMATION AND
NON-PUBLIC DATA EXCISED

Docket No. E002/CI-13-754
DOC Information Request No. 124
Attachments E & F – Page 1 of 1

Monticello Nuclear Generating Plant

NON-PUBLIC DOCUMENT: CONTAINS TRADE SECRET INFORMATION
ENTIRE DOCUMENT IS NON-PUBLIC

Attachments E and F contain confidential security data that the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). Due to security information policies and concerns, the information provided in this response has been marked Non-Public. The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp. 3.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Transformer Replacement		Monticello NGP	$0	$4,000,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2003	2011	TBD	TBD

ESTIMATED CASH FLOW				
ANNUAL	PREVIOUS YRS	2007	2009	
	$0	$2,000,000	$2,000,000	

DESCRIPTION:
Replacement of the Main Transformer and the 1R Transformer to support operation for 20 more years. Potential synergies exist with an extended power uprate project. Xcel has recommended the Main Transformer be replaced to due its service life.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing.
2)

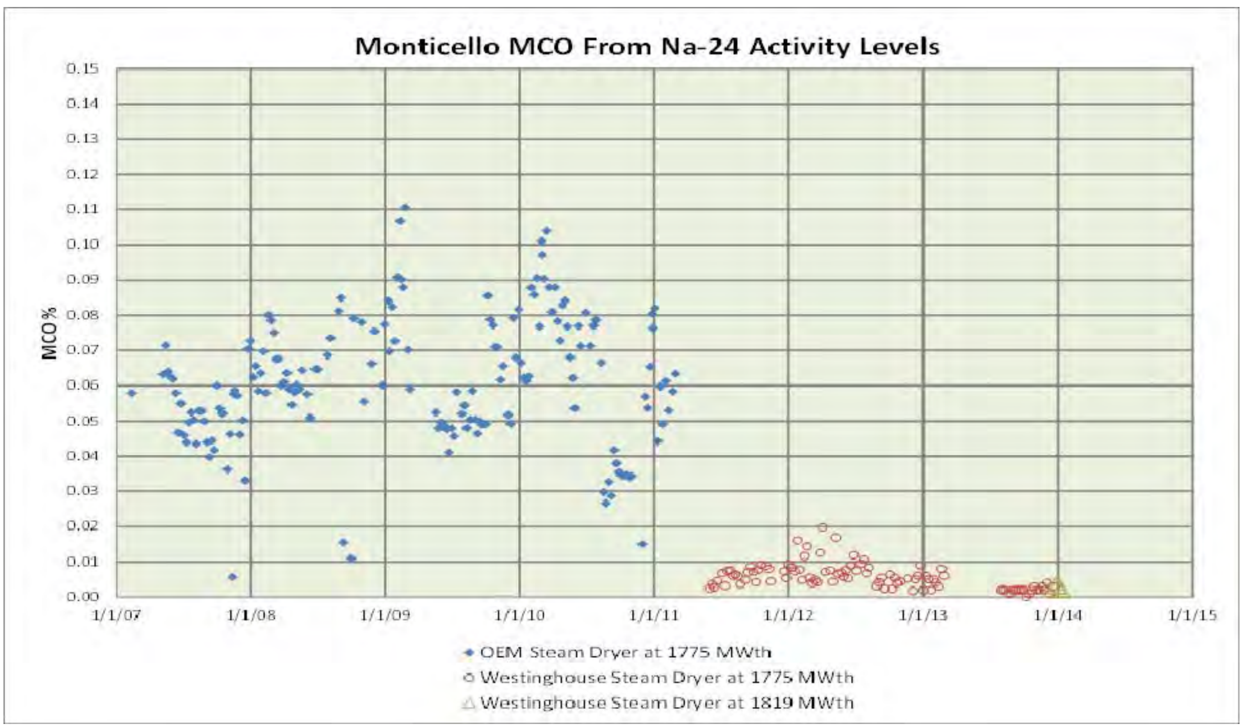
FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

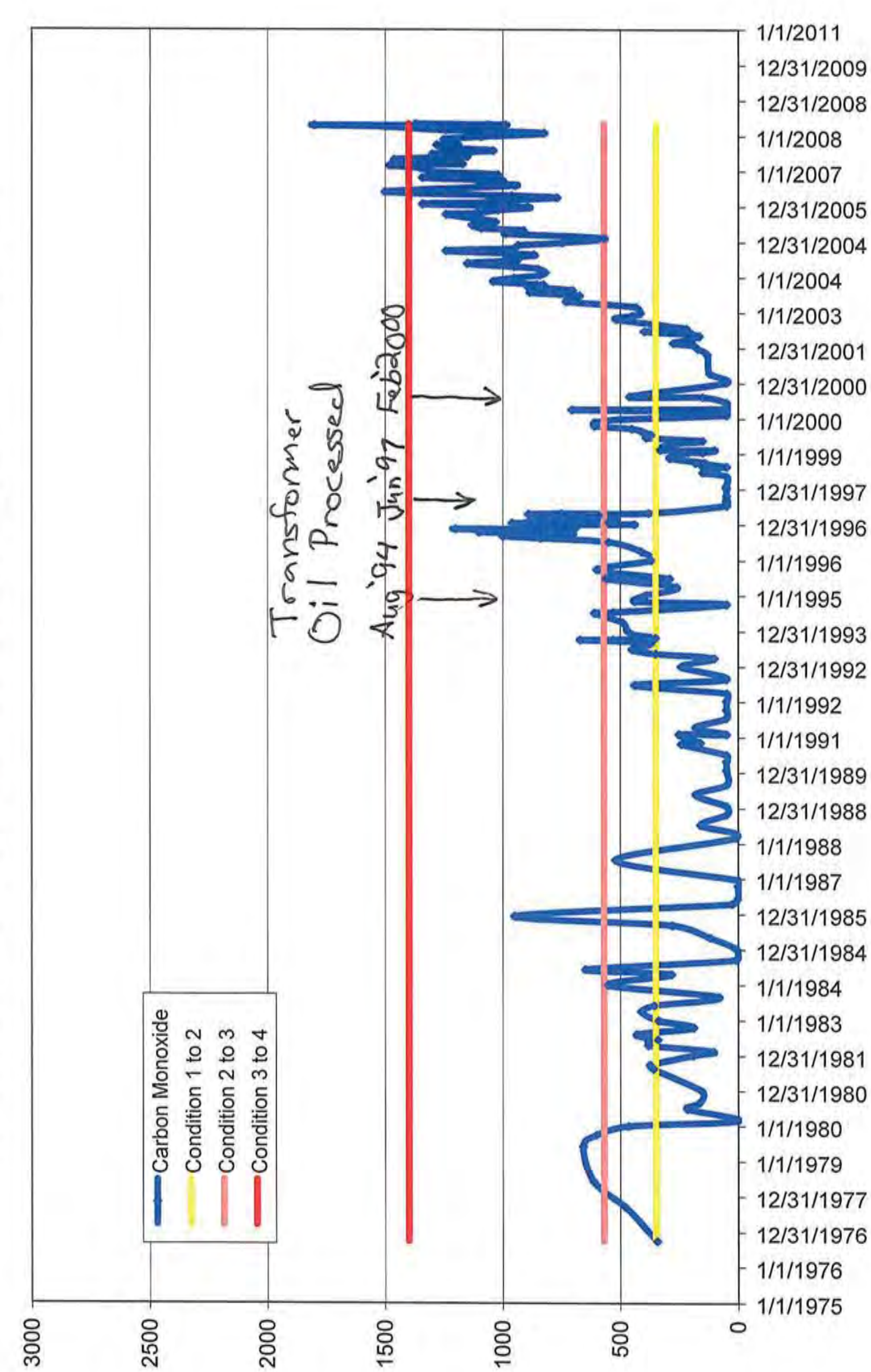
ENVIRONMENTAL ISSUES: None

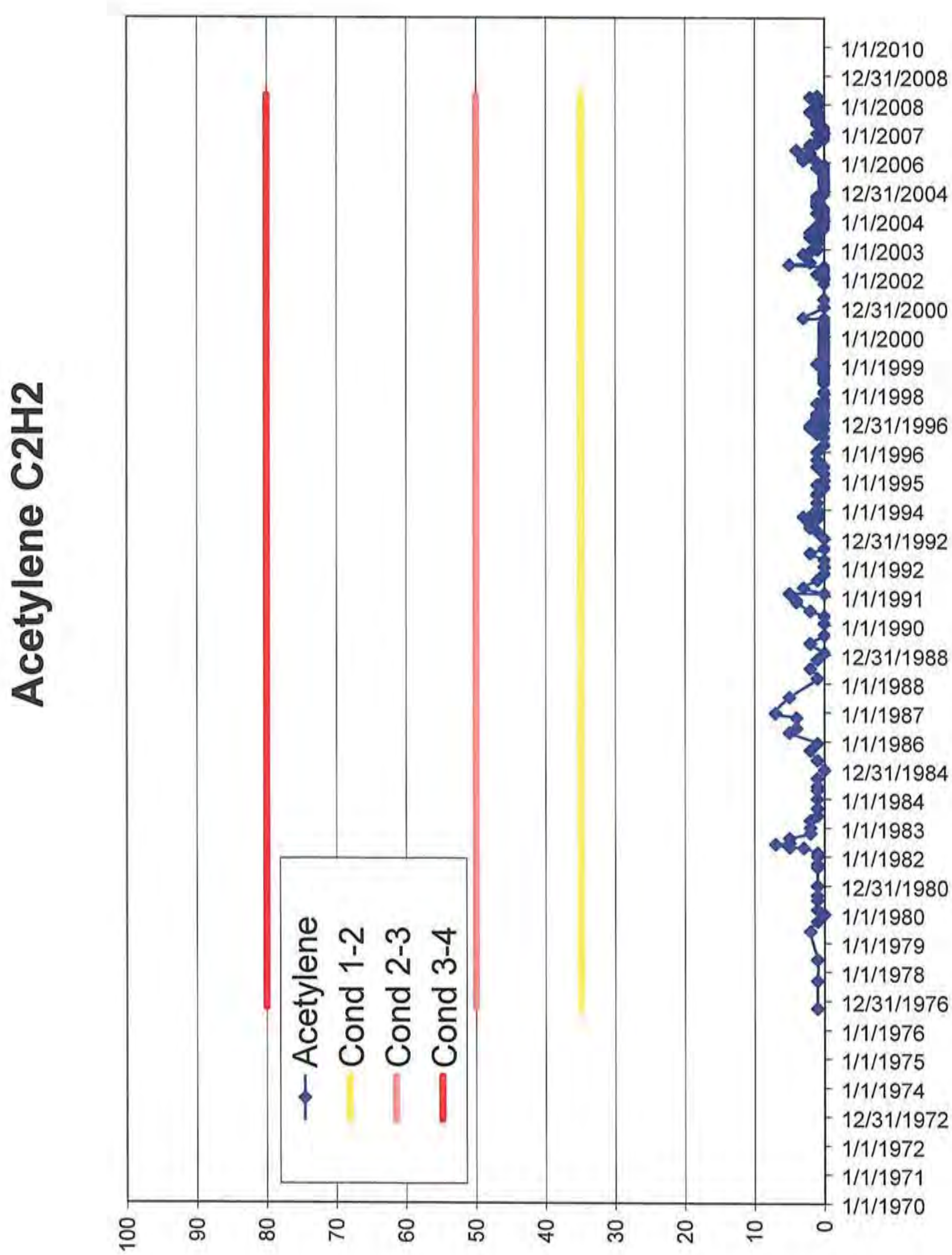
ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.


Monticello MCO From Na-24 Activity Levels
MCO %
0.15
0.14
0.13
0.12
0.11
0.10
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
1/1/07
1/1/08
1/1/09
1/1/10
1/1/11
1/1/12
1/1/13
1/1/14
1/1/15
OEM Steam Dryer at 1775 MWth
Westinghouse Steam Dryer at 1775 MWth
Westinghouse Steam Dryer at 1819 MWth

Historical Carbon Monoxide (CO) Concentration




Acetylene C2H2
Acetylene
Cond 1-2
Cond 2-3
Cond 3-4
0
10
20
30
40
50
60
70
80
90
100
1/1/1970
1/1/1971
1/1/1972
12/31/1972
1/1/1974
1/1/1975
1/1/1976
12/31/1976
1/1/1978
1/1/1979
1/1/1980
12/31/1980
1/1/1982
1/1/1983
1/1/1984
12/31/1984
1/1/1986
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1/1/1988
12/31/1988
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12/31/1992
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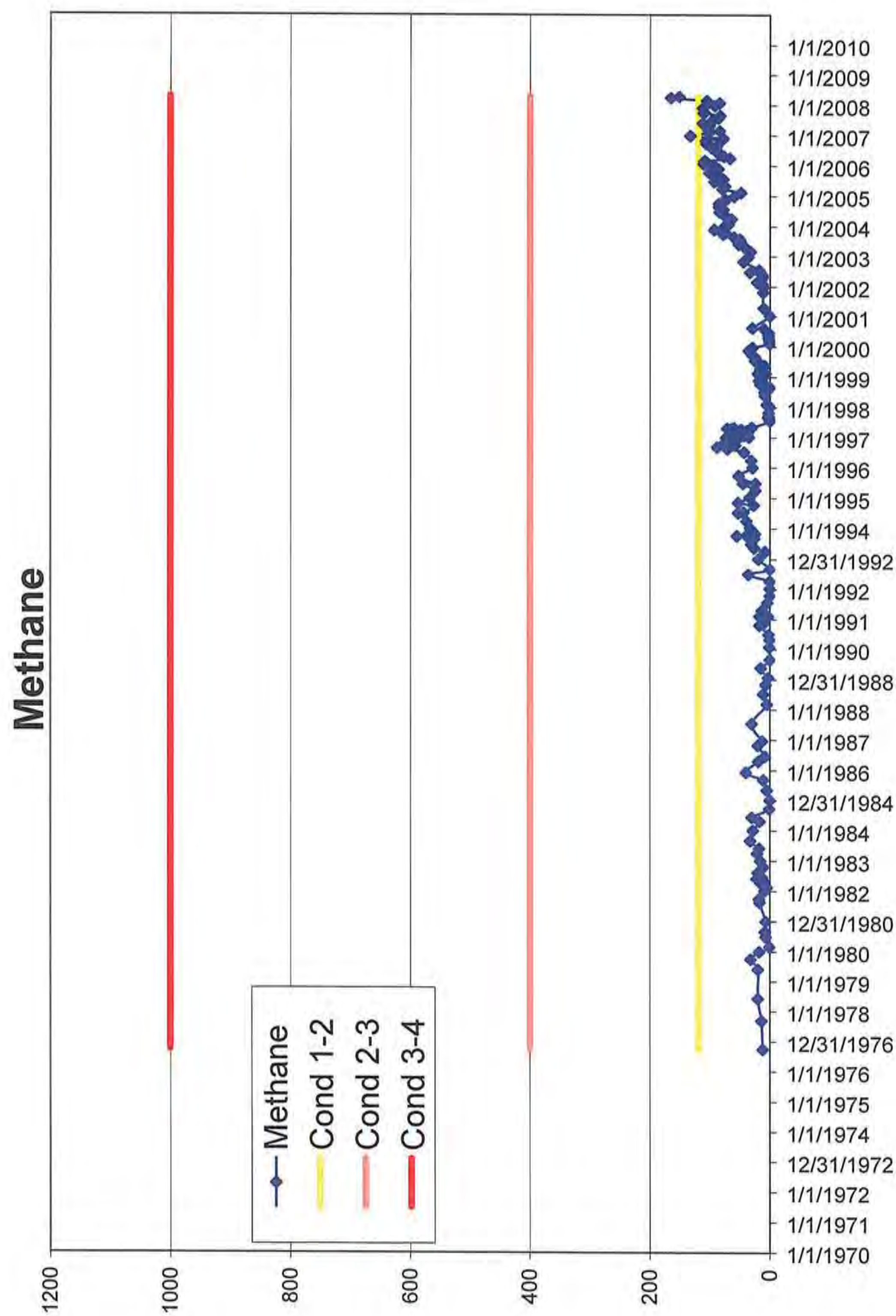
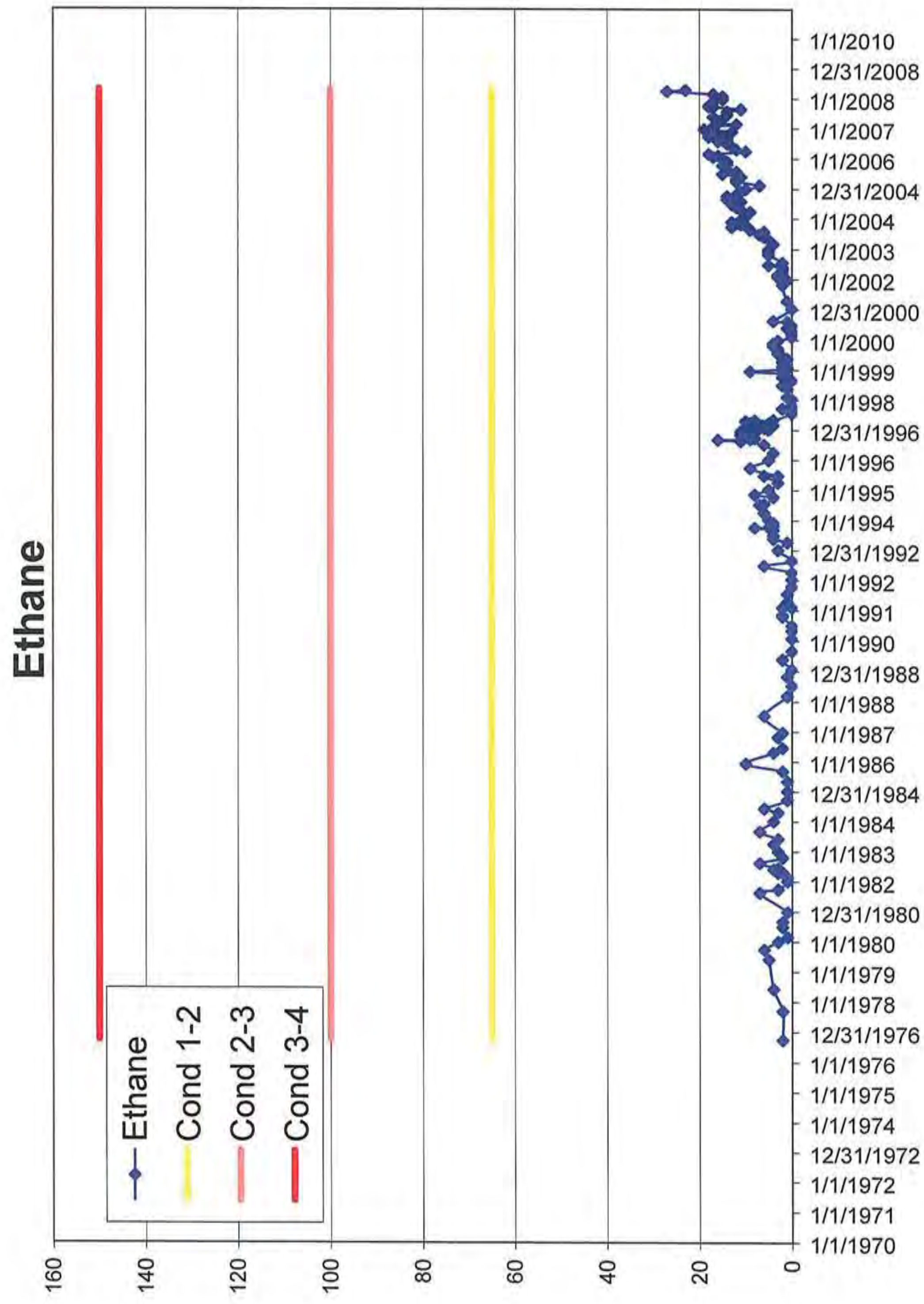
12/31/1996
1/1/1998
1/1/1999
1/1/2000
12/31/2000
1/1/2002
1/1/2003
1/1/2004
12/31/2004
1/1/2006
1/1/2007
1/1/2008
12/31/2008
1/1/2010


Methane
Methane
Cond 1-2
Cond 2-3
Cond 3-4
0
200
400
600
800
1000
1200
1/1/1970
1/1/1971
1/1/1972
12/31/1972
1/1/1974
1/1/1975
1/1/1976
12/31/1976
1/1/1978
1/1/1979
1/1/1980
12/31/1980
1/1/1982
1/1/1983
1/1/1984
12/31/1984
1/1/1986
1/1/1987
1/1/1988
12/31/1988
1/1/1990
1/1/1991
1/1/1992
12/31/1992
1/1/1994
1/1/1995
1/1/1996
1/1/1997
1/1/1998
1/1/1999
1/1/2000
1/1/2001
1/1/2002
1/1/2003
1/1/2004
1/1/2005
1/1/2006
1/1/2007
1/1/2008
1/1/2009
1/1/2010


Ethane
Ethane
Cond 1-2
Cond 2-3
Cond 3-4
160
140
120
100
80
60
40
20
0
1/1/1970
1/1/1971
1/1/1972
12/31/1972
1/1/1974
1/1/1975
1/1/1976
12/31/1976
1/1/1978
1/1/1979
1/1/1980
12/31/1980
1/1/1982
1/1/1983
1/1/1984
12/31/1984
1/1/1986
1/1/1987
1/1/1988
12/31/1988
1/1/1990
1/1/1991
1/1/1992
12/31/1992
1/1/1994
1/1/1995
1/1/1996
12/31/1996
1/1/1998
1/1/1999
1/1/2000
12/31/2000
1/1/2002
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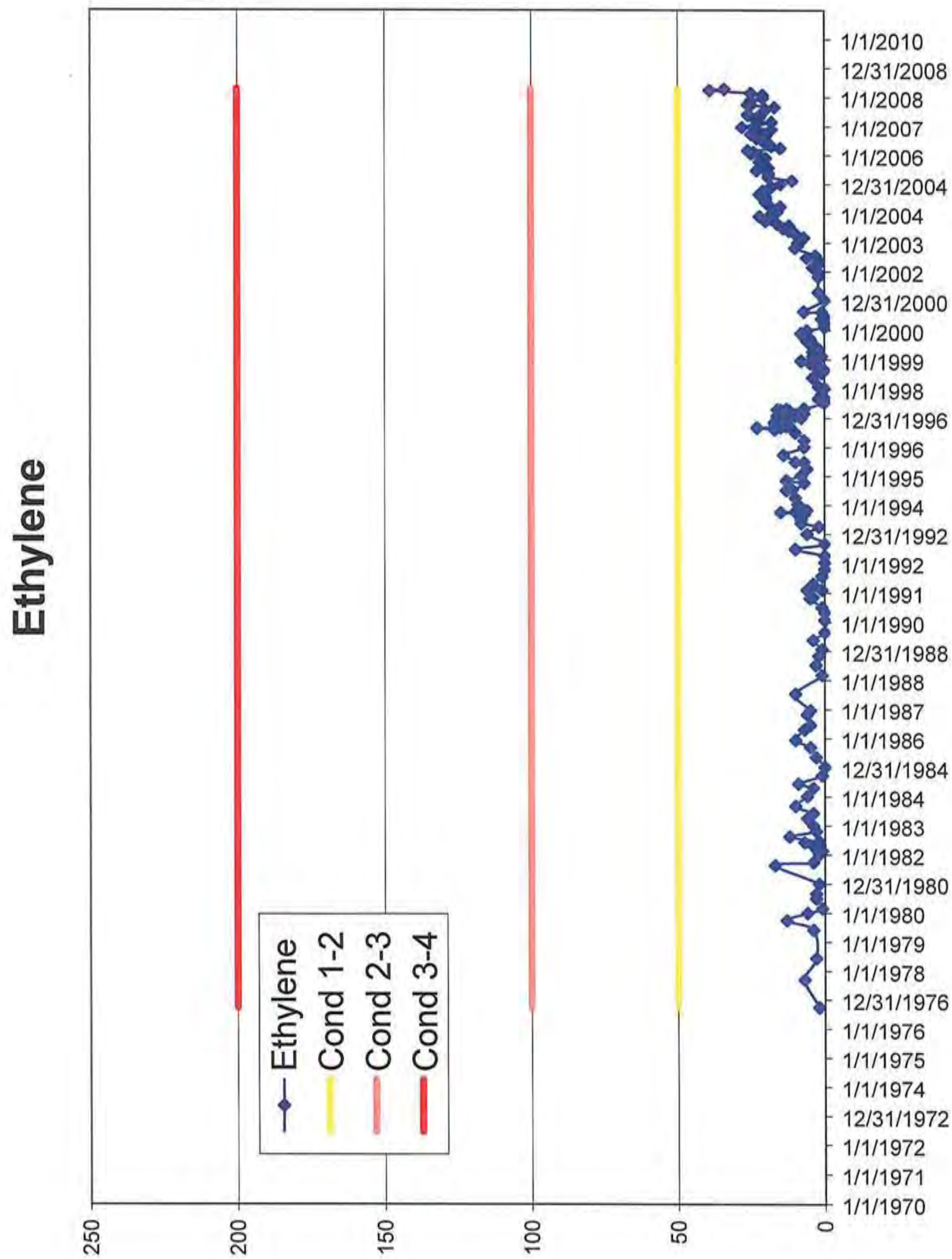
1/1/2006
1/1/2007
1/1/2008
12/31/2008
1/1/2010


Ethylene
Ethylene
Cond 1-2
Cond 2-3
Cond 3-4
250
200
150
100
50
0
1/1/1970
1/1/1971
1/1/1972
12/31/1972
1/1/1974
1/1/1975
1/1/1976
12/31/1976
1/1/1978
1/1/1979
1/1/1980
12/31/1980
1/1/1982
1/1/1983
1/1/1984
12/31/1984
1/1/1986
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12/31/1988
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12/31/1992
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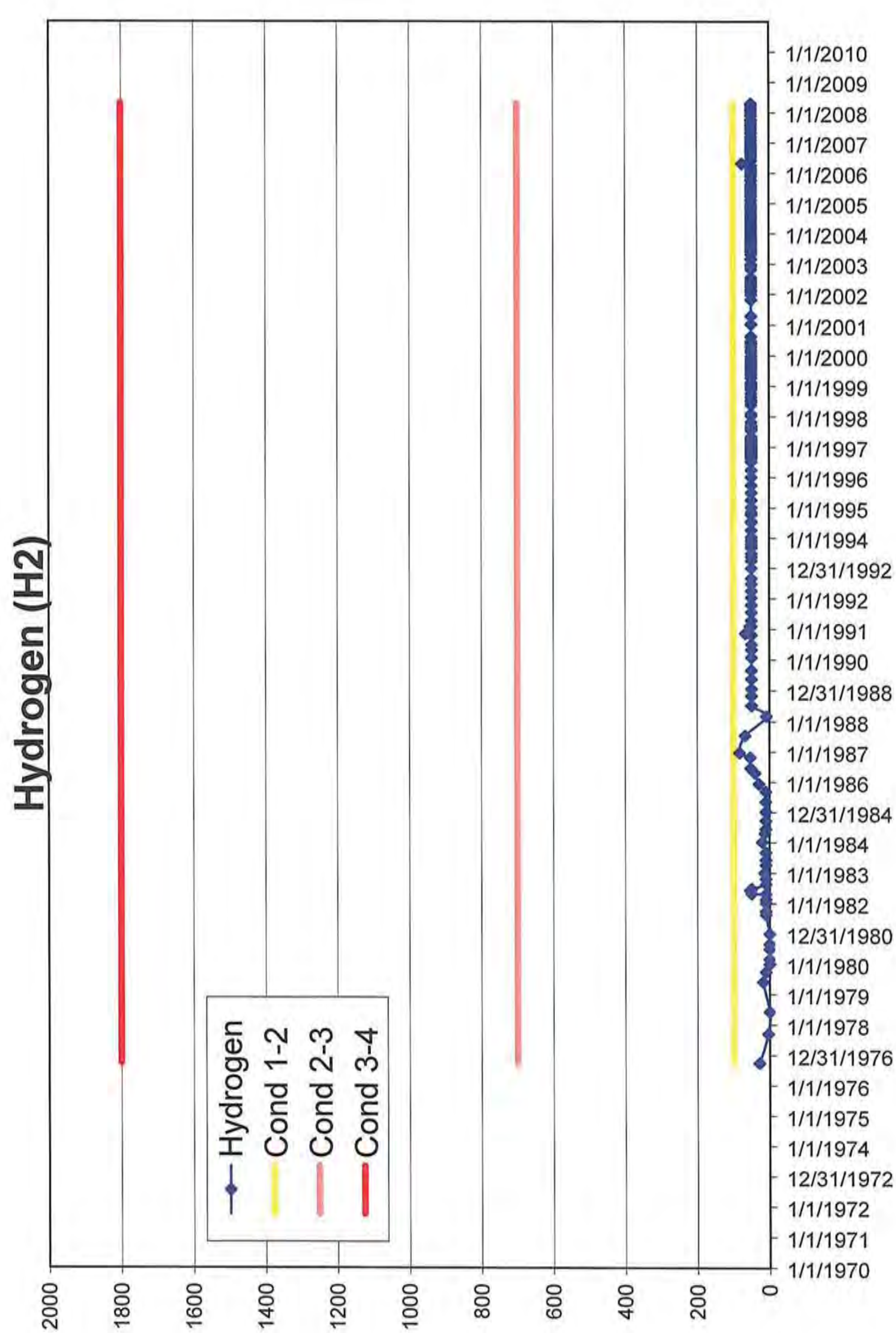
12/31/1996
1/1/1998
1/1/1999
1/1/2000
12/31/2000
1/1/2002
1/1/2003
1/1/2004
12/31/2004
1/1/2006
1/1/2007
1/1/2008
12/31/2008
1/1/2010


Hydrogen (H2)
Hydrogen
Cond 1-2
Cond 2-3
Cond 3-4
2000
1800
1600
1400
1200
1000
800
600
400
200
0
1/1/1970
1/1/1971
1/1/1972
12/31/1972
1/1/1974
1/1/1975
1/1/1976
12/31/1976
1/1/1978
1/1/1979
1/1/1980
12/31/1980
1/1/1982
1/1/1983
1/1/1984
12/31/1984
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1/1/1988
12/31/1988
1/1/1990
1/1/1991
1/1/1992
12/31/1992
1/1/1994
1/1/1995
1/1/1996
1/1/1997
1/1/1998
1/1/1999
1/1/2000
1/1/2001
1/1/2002
1/1/2003
1/1/2004
1/1/2005
1/1/2006
1/1/2007
1/1/2008
1/1/2009
1/1/2010

Monticello D596225 1 M

Labworks #	Date	Acetylene	Ethane	Ethylene	Methane	Carbon Dioxide	Hydrogen	Carbon Monoxide	Oxygen	Date	Comments	% Extracted Gas	DGA Total Combustible Gas
MZ72121	10/1/1976	1	2	2	12	1680	28	343	11	10/1/76			N/A
MZ64409	9/14/1977	1	2	7	14	1700	4	477	3.3	9/14/77			N/A
MZ64350	6/9/1978	1	4	3	20	2600	0	614	3.55	6/9/78			N/A
MZ64184	6/1/1979	2	5	4	20	2550	18	658	15	6/1/79			N/A
MZ64146	10/1/1979	1	6	13	32	3070	10	602	9.44	10/1/79			N/A
MZ64021	1/1/1980	0	3	6	18	1870	0	464	2.69	1/1/80			N/A
MZ64053	3/1/1980	1	1	1	1	37	0	0	0	3/1/80			N/A
MZ63999	7/1/1980	1	2	3	7	2160	0	215	13	7/1/80			N/A
MZ63923	9/1/1980	1	2	3	8	1510	0	166	2.07	9/1/80			N/A
MZ63805	12/31/1980	1	1	2	7	1080	0	153	2340	12/31/80			N/A
MZ63345	8/21/1981	1	7	17	17	2700	10	360	19	8/21/81			N/A
MZ63223	10/1/1981	1	3	4	18	2580	10	374	2.86	10/1/81			N/A
MZ72406	1/7/1982	1	1	2	9	992	10	192	1.25	1/7/82			N/A
MZ72438	2/19/1982	1	1	1	5	645	10	106	0.589	2/19/82			N/A
MZ72473	4/19/1982	3	3	4	16	2100	10	380	1.5	4/19/82			N/A
MZ63143	4/29/1982	5	2	2	9	1920	50	380	11.3	4/29/82			N/A
MZ62960	8/5/1982	7	4	7	22	2400	54	380	5.9	8/5/82			N/A
MZ72579	8/21/1982	5	3	2	13	1750	50	340	4.85	8/21/82			N/A
MZ62804	8/18/1982	5	7	12	20	2310	10	430	16.5	8/18/82			N/A
MZ62623	10/25/1982	2	2	3	11	974	10	189	1.72	10/25/82			N/A
MZ62536	1/4/1983	2	3	4	16	1468	14	337	4.38	1/4/83			N/A
MZ62596	4/6/1983	2	4	6	21	2253	10	412	4.21	4/6/83			N/A
MZ62526	6/7/1983	1	3	4	18	10	10	357	2.11	6/7/83			N/A
MZ62289	9/6/1983	1	7	10	33	2920	10	80	1.88	9/6/83			N/A
MZ62045	1/6/1984	1	4	6	28	736	20	552	1.26	1/6/84			N/A
MZ61964	4/24/1984	1	3	4	17	1140	13	282	1.07	4/24/84			N/A
MZ61759	6/13/1984	1	6	9	30	2560	10	649	8.81	6/13/84			N/A
MZ61256	9/24/1984	1	1	1	1	161	10	10	1.82	9/24/84			N/A
MZ61186	1/8/1985	0	1	0	0	60	10	6	1.09	1/8/85			N/A
MZ72861	5/9/1985	1	1	3	5	1000	10	119	2.24	5/9/85			N/A
MZ60777	9/12/1985	2	2	5	11	1630	10	279	2.87	9/12/85			N/A
MZ60636	12/12/1985	1	10	10	40	2400	29	950	3	12/12/85			N/A
MZ72933	4/23/1986	5	4	7	19	2000	40	25	2.3	4/23/86			N/A
MZ60430	6/19/1986	4	2	5	8	1340	52	0	15	6/19/86			N/A
MZ72889	10/29/1986	4	3	6	20	1700	53	0	9.6	10/29/86			N/A
MZ59951	12/23/1986	7	2	5	13	1050	83	0	1.93	12/23/86			N/A
MZ59282	7/17/1987	5	6	10	30	2400	67	520	4.6	7/17/87			N/A
MZ73022	3/8/1988	1	1	1	5	300	8	10	0.68	3/8/88			N/A
MZ73340	7/11/1988	2	0	3	11	1200	49	160	6800	7/11/88			N/A
MZ71985	11/2/1988	1	1	2	7	900	49	49	1200	11/2/88			N/A
MZ71790	1/25/1989	0	0	1	3	260	49	49	850	1/25/89			N/A
MZ71617	5/23/1989	2	2	4	15	1300	49	180	15000	5/23/89			N/A
MZ71169	9/1/1989	0	0	0	0	0	49	49	0	9/1/89			N/A
MZ70711	1/31/1990	0	0	0	1	120	49	49	1200	1/31/90			N/A
MZ70369	5/3/1990	0	0	0	0	0	49	49	0	5/3/90			N/A
MZ69893	7/5/1990	2	0	1	2	130	49	49	150	7/5/90			N/A
MZ69416	10/25/1990	4	2	5	17	1200	49	240	2800	10/25/90			N/A
MZ69450	11/12/1990	4	2	4	11	770	66	160	1100	11/12/90			N/A
MZ58273	2/7/1991	5	2	6	17	440	54	250	750	2/7/91			N/A

MZ69106	2/8/1991	0	0	1	3	140	49	49	280	2/8/91	N/A
MZ68996	4/18/1991	3	1	4	13	620	49	180	770	4/18/91	N/A
MZ68488	7/25/1991	1	1	1	4	190	49	50	310	7/25/91	N/A
MZ68216	10/21/1991	0	0	0	0	0	49	49	0	10/21/91	N/A
MZ67992	1/14/1992	0	0	0	0	0	49	49	0	1/14/92	N/A
MZ67769	4/8/1992	0	0	0	0	0	49	49	0	4/8/92	N/A
MZ67484	6/29/1992	2	6	10	36	2200	49	440	11000	6/29/92	N/A
MZ67149	9/1/1992	0	0	0	0	0	49	49	0	9/1/92	N/A
MZ66863	1/5/1993	0	3	6	19	1300	49	240	1700	1/5/93	N/A
MZ66647	4/5/1993	1	1	2	8	530	49	100	1200	4/5/93	N/A
MZ66439	5/19/1993	2	4	8	26	1900	49	350	1900	5/19/93	N/A
MZ66311	7/1/1993	2	4	8	31	2100	49	450	890	7/1/93	N/A
MZ66053	9/7/1993	1	4	7	26	1900	49	370	1500	9/7/93	N/A
MZ65957	10/6/1993	3	8	15	55	3600	49	670	12000	10/6/93	N/A
MZ65901	10/11/1993	2	5	10	39	2500	49	530	2600	10/11/93	N/A
MZ65805	10/29/1993	1	4	6	25	1700	49	350	4300	10/29/93	N/A
MZ65713	12/6/1993	1	4	8	29	2200	49	450	2800	12/6/93	N/A
MZ65662	1/12/1994	1	5	9	33	2100	49	470	3500	1/12/94	N/A
MZ65606	4/7/1994	1	6	10	39	2400	49	490	1400	4/7/94	N/A
MZ57950	7/11/1994	1	7	13	53	3200	49	610	7500	7/11/94	N/A
MZ65140	7/21/1994	1	6	11	44	3100	49	530	11000	7/21/94	N/A
MZ57818	10/11/1994	0	4	7	27	1500	49	49	1600	10/11/94	N/A
MZ64557	11/10/1994	1	8	13	53	3100	49	440	10000	11/10/94	N/A
MZ57661	1/10/1995	0	5	8	34	2000	49	390	2200	1/10/95	N/A
MZ57257	4/5/1995	0	3	6	24	1500	49	260	3500	4/5/95	N/A
MZ56874	6/30/1995	1	6	10	45	2800	49	560	7100	6/30/95	N/A
MZ56872	6/30/1995	0	3	7	24	1400	49	290	1200	6/30/95	N/A
MZ56324	9/28/1995	1	9	14	52	3500	49	600	16000	9/28/95	N/A
MZ55980	1/4/1996	1	5	7	29	1700	49	370	7800	1/4/96	N/A
MZ55758	4/1/1996	0	4	7	31	1300	49	410	4000	4/1/96	N/A
MZ55386	7/8/1996	0	6	10	43	1200	49	550	2300	7/8/96	N/A
MZ55266	8/16/1996	1	11	17	71	4600	49	840	2100	8/16/96	N/A
MZ55192	9/5/1996	1	16	23	88	5900	49	1000	9800	9/5/96	N/A
MZ55203	9/11/1996	1	9	15	67	4500	49	830	2900	9/11/96	N/A
MZ55128	9/16/1996	1	11	17	74	4900	49	960	4000	9/16/96	N/A
MZ55150	9/23/1996	1	8	13	65	4100	49	790	2100	9/23/96	N/A
MZ55168	9/30/1996	1	8	12	58	3600	49	700	3500	9/30/96	N/A
MZ55119	10/7/1996	1	9	15	72	4300	49	870	2100	10/7/96	N/A
MZ55003	10/14/1996	0	9	15	71	4300	49	1100	1900	10/14/96	N/A
MZ55015	10/21/1996	1	10	16	73	4600	49	1000	5800	10/21/96	N/A
MZ54947	10/28/1996	1	10	16	68	4200	49	900	1900	10/28/96	N/A
MZ54964	11/4/1996	2	11	17	75	4400	49	860	2600	11/4/96	N/A
MZ54980	11/11/1996	1	11	17	73	4400	49	1100	3000	11/11/96	N/A
MZ54891	11/18/1996	1	9	15	72	4100	49	1200	3100	11/18/96	N/A
MZ54900	11/19/1996	1	9	14	59	3800	49	780	1800	11/19/96	N/A
MZ54933	11/25/1996	2	10	15	64	4000	49	820	1500	11/25/96	N/A
MZ54856	12/2/1996	1	8	13	59	3400	49	690	1900	12/2/96	N/A
MZ54886	12/9/1996	1	8	13	58	3300	49	730	2300	12/9/96	N/A
MZ54756	12/16/1996	1	11	16	70	4100	49	880	1900	12/16/96	N/A
MZ54766	12/23/1996	1	8	12	57	3400	49	740	1700	12/23/96	N/A
MZ54774	12/30/1996	1	8	14	73	4000	49	950	1600	12/30/96	N/A
MZ54708	1/6/1997	0	5	8	35	2200	49	440	2400	1/6/97	N/A
MZ54742	1/13/1997	1	8	12	50	3300	49	700	1500	1/13/97	N/A
MZ54660	1/20/1997	1	10	16	67	4000	49	960	2100	1/20/97	N/A
MZ54673	1/28/1997	1	6	10	43	2600	49	550	990	1/28/97	N/A

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MZ54685	2/3/1997	1	10	16	69	4200	49	890	1400	2/3/97		N/A
MZ54690	2/10/1997	1	10	14	59	3800	49	860	1100	2/10/97		N/A
MZ54615	2/17/1997	1	7	12	57	3500	49	840	2000	2/17/97		N/A
MZ54620	2/24/1997	1	8	12	52	3200	49	650	1300	2/24/97		N/A
MZ54628	3/3/1997	1	4	7	37	2100	49	520	1600	3/3/97		N/A
MZ54568	3/10/1997	1	9	13	58	3500	49	710	1400	3/10/97		N/A
MZ54585	3/17/1997	0	8	12	57	3400	49	760	2400	3/17/97		N/A
MZ54593	3/24/1997	0	5	8	39	2300	49	530	1300	3/24/97		N/A
MZ54596	3/31/1997	1	9	14	59	3700	49	830	1200	3/31/97		N/A
MZ54550	4/7/1997	1	8	12	48	3100	49	590	1500	4/7/97		N/A
MZ54484	4/14/1997	0	10	15	64	4000	49	800	1600	4/14/97		N/A
MZ54499	4/21/1997	1	10	16	71	4400	49	690	4600	4/21/97		N/A
MZ54513	4/28/1997	1	8	13	60	3600	49	750	3300	4/28/97		N/A
MZ54434	5/5/1997	0	4	7	30	1900	49	380	3600	5/5/97		N/A
MZ54287	7/22/1997	0	0	0	0	9	49	49	660	7/22/97		N/A
MZ54217	8/6/1997	0	0	1	1	150	49	49	4600	8/6/97		N/A
MZ54157	8/11/1997	0	0	0	1	120	49	49	7800	8/11/97		N/A
MZ54113	8/20/1997	0	0	1	0	51	49	49	1400	8/20/97		N/A
MZ54137	8/25/1997	0	0	1	1	110	49	49	1200	8/25/97		N/A
MZ54087	9/5/1997	1	0	2	3	380	49	49	7400	9/5/97		N/A
MZ54060	9/18/1997	0	2	0	2	190	49	49	1400	9/18/97		N/A
MZ53780	10/29/1997	0	0	1	2	310	49	49	2900	10/29/97		N/A
MZ53566	1/13/1998	0	0	0	0	0	49	49	0	1/13/98		N/A
MZ53366	2/4/1998	0	1	2	5	280	49	51	3100	2/4/98		N/A
MZ53129	5/22/1998	0	1	4	8	730	49	49	16000	5/22/98		N/A
MZ52845	6/30/1998	0	2	3	9	1000	49	150	14000	6/30/98		N/A
MZ52717	7/20/1998	0	1	1	5	430	49	93	600	7/20/98		N/A
MZ52412	8/28/1998	0	1	2	8	740	49	150	1600	8/28/98		N/A
MZ52411	8/28/1998	0	0	0	0	0	49	49	0	8/28/98		N/A
MZ52288	10/6/1998	0	2	3	16	1200	49	180	21000	10/6/98		N/A
MZ52287	10/6/1998	0	1	2	8	530	49	140	2300	10/6/98		N/A
MZ51990	11/23/1998	0	2	5	18	1600	49	290	5200	11/23/98		N/A
MZ51947	12/18/1998	0	9	8	15	1200	49	250	1600	12/18/98		N/A
MZ51973	1/18/1999	1	1	3	13	1000	49	210	1300	1/18/99		N/A
MZ51978	1/19/1999	1	1	2	9	800	49	150	3200	1/19/99		N/A
MZ51815	2/15/1999	0	1	1	7	520	49	100	620	2/15/99		N/A
MZ51814	2/15/1999	0	2	4	20	1500	49	330	2100	2/15/99		N/A
MZ51569	4/12/1999	0	2	4	16	1500	49	300	7500	4/12/99		N/A
MZ51410	5/20/1999	0	1	2	9	730	49	150	1300	5/20/99		N/A
MZ51293	6/21/1999	0	2	3	18	1400	49	390	400	6/21/99		N/A
MZ51058	7/21/1999	0	3	5	25	2200	49	370	12000	7/21/99		N/A
MZ50887	8/27/1999	0	3	6	25	2500	49	410	3100	8/27/99		N/A
MZ73720	9/21/1999	0	3	5	29	2600	49	450	9000	9/21/99		N/A
MZ73888	10/21/1999	0	4	7	32	3400	49	610	2600	10/21/99		N/A
MZ73934	11/22/1999	0	4	8	35	2600	49	610	5300	11/22/99		N/A
MZ74136	12/27/1999	0	3	6	29	2600	49	500	6100	12/27/99		N/A
MZ74308	2/10/2000	0	0	0	0	22	49	49	1700	2/10/00		N/A
MZ74393	3/15/2000	0	0	0	1	270	49	49	17000	3/15/00		N/A
MZ74533	4/17/2000	0	0	0	2	280	49	49	6900	4/17/00		N/A
MZ74007	5/25/2000	0	1	1	2	460	49	49	2600	5/25/00		N/A
MZ74730	6/21/2000	0	0	0	2	270	49	49	7500	6/21/00		N/A
MZ75055	8/14/2000	0	1	1	10	1300	49	150	10000	8/14/00		N/A
EE32734	8/20/2000	3	4	7	29	1930	49	460	1990	8/20/00	2.9	503
MZ75731	1/12/2001	0	0	0	0	0	49	49	0	1/12/01		N/A
MZ75907	4/16/2001	0	1	2	10	920	49	120	8900	4/16/01		N/A

MZ77276	10/29/2001	0	2	2	11	1300	49	130	5200	10/29/01			N/A
MZ77483	12/27/2001	0	1	2	11	960	49	170	1500	12/27/01			N/A
EE13379	1/31/2002	0	3	3	12	944	49	185	1480	1/31/02		1.5	203
EE16028	2/26/2002	1	3	4	21	1620	49	274	2220	2/26/02		2.6	307
EE19130	4/4/2002	0	2	2	14	1160	49	211	956	4/4/02		1.7	232
EE21538	5/7/2002	0	2	2	11	868	49	164	1070	5/7/02		1.2	179
EE23149	5/29/2002	0	2	2	13	1010	49	195	1070	5/29/02		1.5	212
EE26522	6/25/2002	5	5	6	33	2300	49	398	7930	6/25/02		6.7	447
EE29325	7/23/2002	2	2	3	18	1260	49	218	821	7/23/02		1.9	256
EE38999	10/29/2002	3	5	10	44	2690	49	517	2840	10/29/02		4.8	619
EE42297	12/3/2002	2	5	9	39	2370	49	448	3810	12/3/02		4.7	533
EE44350	12/30/2002	1	5	9	36	2220	49	414	1870	12/30/02		4.2	465
EE49696	3/5/2003	1	4	7	32	1890	49	433	5110	3/5/03		5.2	477
EE54170	4/28/2003	1	5	10	42	2600	49	730	2120	4/28/03		5	788
EE57418	6/2/2003	2	6	12	52	3240	49	686	9840	6/2/03	Very slight increase in organic gases from previous	9.4	758
EE60287	6/30/2003	1	7	14	49	3300	49	672	3530	6/30/03	No significant change from previous	7.7	743
EE64167	8/1/2003	2	6	12	50	3230	49	884	8840	8/1/03	No significant change from previous	9.5	954
EE66602	8/25/2003	1	9	16	60	4040	49	702	2800	8/25/03	No significant change from previous	6.5	788
EE70207	9/29/2003	0	13	20	78	4250	49	893	6520	9/29/03	No significant change from previous	7.5	1004
EE71825	10/20/2003	1	10	18	74	4280	49	826	4100	10/20/03	No significant change from previous	7	929
EE72427	10/27/2003	1	11	18	79	4200	49	856	7130	10/27/03	No significant change from previous	9.3	965
EE74671	11/24/2003	0	13	22	93	4440	49	1040	6880	11/24/03	No significant change from previous	8.2	1165
EE76736	12/29/2003	0	11	18	76	3740	49	951	6290	12/29/03	No significant change from previous	7.7	1056
EE78678	1/27/2004	0	10	16	69	4230	49	843	3900	1/27/04	No significant change from previous	7.3	938
EE81089	2/26/2004	0	10	16	68	4360	49	818	3670	2/26/04	No change from previous analysis	7.5	912
EE84130	4/1/2004	1	9	15	64	3730	49	848	3020	4/1/04	No change from previous analysis	7.5	937
EE86687	4/26/2004	0	11	19	73	4980	49	952	4070	4/26/04	No change from previous analysis	8.5	1065
EE89914	5/27/2004	0	12	20	76	5090	49	1150	5350	5/27/04	No change from previous analysis	8.4	1255
EE93416	6/30/2004	1	13	20	84	5320	49	937	10600	6/30/04	Slight increases from previous analysis	13	1055
EE96369	7/29/2004	1	11	20	78	5460	49	977	7270	7/29/04	No change from previous analysis	10.3	1087
EE99156	8/27/2004	1	14	22	85	5430	49	867	4580	8/27/04	No change from previous analysis	8.7	989
EF02397	10/4/2004	1	14	21	85	4860	49	1240	7750	10/4/04	No change from previous analysis	10.8	1356
EF05061	10/29/2004	1	12	19	76	4960	49	951	6960	10/29/04	No change from previous analysis	10.7	1059
EF06388	11/29/2004	0	11	18	75	5100	49	934	4370	11/29/04	No change from previous analysis	6.3	1038
EF08525	12/30/2004	0	10	15	60	3760	49	747	8020	12/30/04		6.5	832
EF14871	2/14/2005	0	7	11	48	2770	49	569	12200	2/14/05	Slight decreases from previous analysis	10.3	656
EF18880	3/31/2005	0	12	19	79	4040	49	988	2510	3/31/05	Methane is up slightly from previous analysis	7.9	1116
EF21047	5/2/2005	0	12	19	75	4490	49	912	5270	5/2/05	No change from previous analysis	8.8	1032
EF22322	5/24/2005	0	11	19	80	5030	49	1090	4440	5/24/05	No change from previous analysis	9.3	1202
EF26938	6/28/2005	0	15	23	93	5950	49	1130	4800	6/28/05	Slight increases from previous analysis	10.3	1277
EF32821	7/28/2005	0	12	19	78	5340	49	1030	5290	7/28/05	Slight decreases from previous analysis	9.7	1143
EF34141	8/24/2005	0	14	20	85	5630	49	1090	7880	8/24/05	No change from previous analysis	10.7	1210
EF38835	10/14/2005	0	15	22	101	6410	49	1240	4570	10/14/05	Slight increases from previous analysis	10.3	1399
EF38926	10/26/2005	1	14	21	93	5730	49	1110	3640	10/26/05	No change from previous analysis	9.3	1240
EF41561	11/28/2005	0	14	20	86	5570	49	1020	6730	11/28/05	No change from previous analysis	10	1143
EF44389	12/29/2005	1	15	22	93	6160	49	892	3050	12/29/05	No change from previous analysis	9.3	1023
EF45945	1/26/2006	3	17	25	111	5390	49	1340	4670	1/26/06	Slight increases from previous analysis	9.5	1496
EF46818	2/13/2006	3	16	24	106	4790	49	1070	4780	2/13/06	No change from previous analysis	9.5	1223
EF48693	3/2/2006	3	18	26	109	5210	49	1060	4210	3/2/06	No change from previous analysis	9.1	1212
EF51435	4/3/2006	2	10	15	67	4030	49	768	8180	4/3/06	Overall decreases from previous analysis	9.9	862
EF53076	4/26/2006	2	12	18	77	5350	75	962	7760	4/26/06	Slight increases from previous analysis but	10.2	1146
EF56482	6/1/2006	4	13	20	86	6490	49	1500	4090	6/1/06	Slight increases from previous analysis	9.7	1622
EF60595	7/7/2006	2	14	20	89	7250	49	49	3490	7/7/06	Carbon monoxide was not detected due to instrument failure	9.9	125
EF65194	8/7/2006	2	16	23	97	4970	49	947	3750	8/7/06	Slight increase in methane from previous analysis	8.2	1085
EF65530	8/28/2006	1	14	20	89	5150	49	1100	6470	8/28/06	No change from previous analysis	9.8	1225

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EF68639	9/26/2006	1	18	25	106	5410	49	1000	2670	9/26/06	Slight increases from previous analysis	8.9		1152
EF72489	10/27/2006	0	16	23	107	5810	49	1340	5950	10/27/06	Carbon oxides are up slightly from previous analysis	10.3		1489
EF72490	11/27/2006	0	13	18	78	4730	49	1020	4000	11/27/06	Overall decreases from previous analysis	7.5		1129
EF75310	12/27/2006	1	19	28	133	5950	49	1300	5330	12/27/06	Overall increases from previous analysis	10.1		1484
EF76206	2/2/2007	0	17	23	102	5870	49	1350	3510	2/2/07	No change from previous analysis	9.2		1494
EF78090	3/1/2007	0	12	18	84	4800	49	1480	9010	3/1/07	Organics are down from previous analysis	11.5		1598
EF79594	3/16/2007	0	16	23	103	5360	49	1170	4930	3/16/07	Slight increases from January sample but	10.2		1311
EF84819	5/1/2007	1	15	22	101	5630	49	1460	6380	5/1/07	No change from previous analysis	11.2		1602
EF85409	6/1/2007	1	17	26	112	6080	49	1150	5080	6/1/07	Slight increases from previous analysis	9.7		1306
EF89700	6/27/2007	1	14	21	97	6690	49	1300	4730	6/27/07	Organics are down slightly from previous analysis	10		1433
EF93593	8/3/2007	1	14	20	86	5880	49	1040	12300	8/3/07	No change from previous analysis	11.5		1164
EF94501	8/31/2007	1	11	17	83	5350	49	1260	9830	8/31/07	No change from previous analysis	13.5		1376
EF98387	10/1/2007	2	17	25	111	6480	49	1280	5070	10/1/07	Overall increases from previous analysis	9.9		1438
EF99241	10/5/2007	1	18	26	109	5920	49	1190	7110	10/5/07	No change from previous analysis	9.6		1344
EG00444	11/28/2007	1	17	25	112	5760	49	1250	3700	11/28/07	No change from previous analysis	9.2		1402
EG01720	12/26/2007	1	15	21	92	4650	49	1090	3010	12/26/07	No change from previous analysis	7.6		1219
EG03829	2/1/2008	1	15	21	84	4060	49	823	9350	2/1/08	No change from previous analysis	9.2		944
EG06182	2/28/2008	1	17	25	105	7060	49	1240	3240	2/28/08	Overall increases from previous analysis	9		1386
EG09047	4/3/2008	2	27	39	165	8990	49	1500	3290	4/3/08	Overall increases from previous analysis	9.4		1732
EG09733	4/17/2008	1	23	34	151	6400	49	1800	3250	4/17/08	Slight decreases from previous analysis	9.2		2006
SIDN		Acetylene	Ethane	Ethylene	Methane	Carbon Dioxide	Hydrogen	Carbon Monoxide	Oxygen	Expr1	CM01	Percent	Extracted Gas	DGA Total Combustible Gas

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Extended Power Uprate

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Extended Power Uprate	Monticello NGP	$0	$22,000,000

OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2003	2007	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	2009
	$0	$0	$1,000,000	$2,500,000	$3,500,000	$10,000,000	$5,000,000

DESCRIPTION:
Perform analysis and physical plant modifications to extend the power level up to at least 1880 Mwth. The power uprate project performed in 1996 performed many of the analysis at the 1880 Mwth power level. Additionally the GE topical reports provide the bases for extending power up to 120% of the license value or 2004 Mwth. One of the key aspects of this project would be to perform an optimization study, taking into consideration synergies with replacement of components for license renewal to determine the optimum power level.

Potential projects to support an uprate are: Upgrade turbine flow path, upgrade generator cooling and excitation, Upgrades to the feedwater system valves, and pumps and heaters.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):
Benefits of performing this project are to increase the plant output.

ALTERNATIVES:

1) Do nothing.
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

TBD- The financial benefit of extending the power level will be significant.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Power Cable Replacement		Monticello NGP	-	
OPERATING CO.	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012	
	$0	$ 10,000,000	$ 15,000,000	$10,000,000	$10,000,000	

DESCRIPTION:
Replace aged cables to increase plant reliability.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Static Excitation System		Monticello NGP	$0	$2,075,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2003	2005	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007
	$0	-	$1,575,000	$500,000	-	-

DESCRIPTION:
The self-excitation of the generator should be replaced to support extended plant operation.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

NMC
Committed to Nuclear Excellence

THE MONTICELLO LICENSE RENEWAL PLAN

Roger Newton and Patrick Burke

Overview Presentation

July 31st, 2001

Purpose and Objective

- Update on industry activity and process for license renewal applications (Roger)
- Review the results of the license renewal study (Pat)
- Develop a plan to pursue project approval and funding (Pat)
- Review NMC License Renewal Strategy and Plan and gain consensus (Roger)

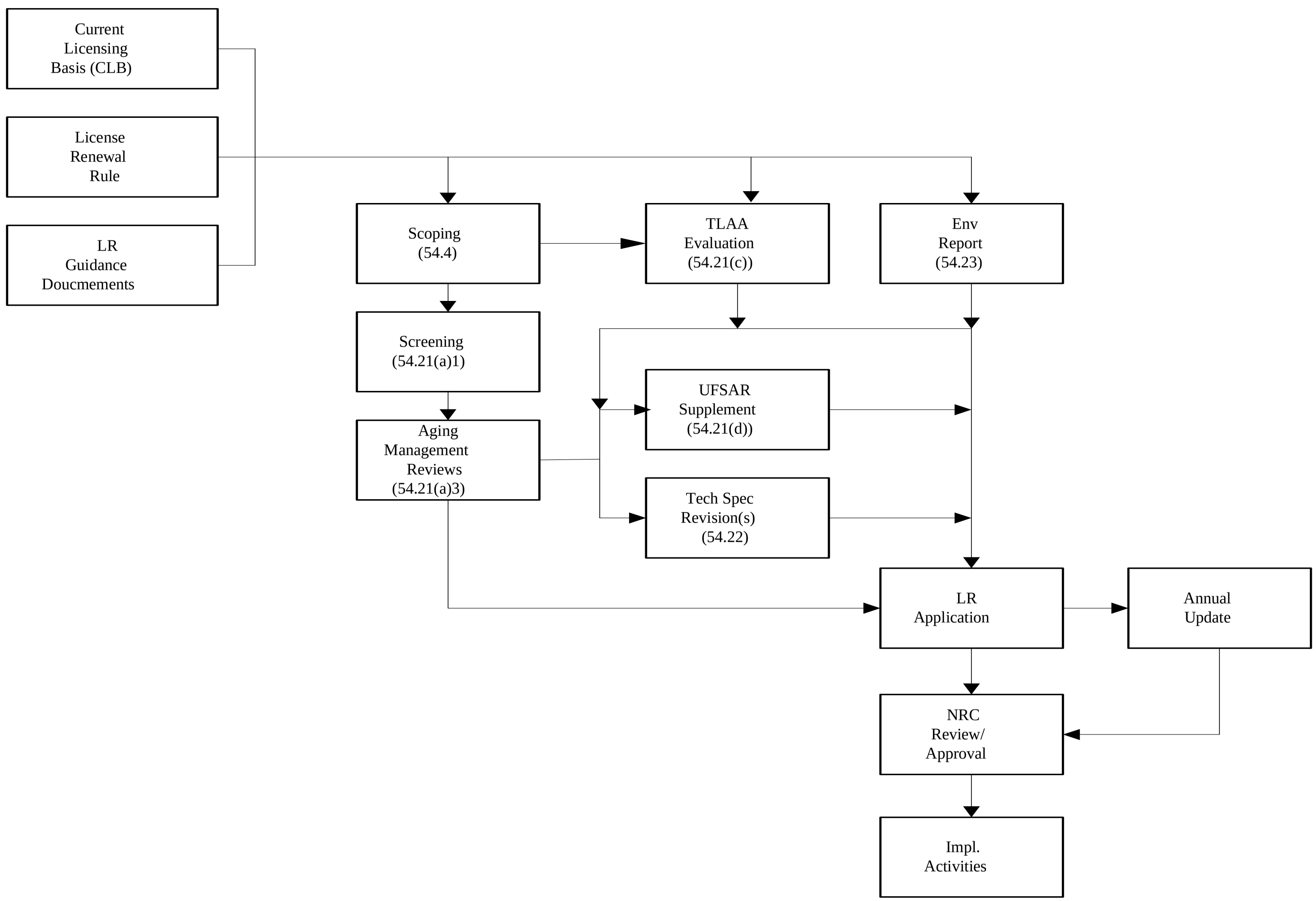
Industry Experience

- **Successful Applicants**
- Calvert Cliffs 1&2, Oconee 1,2&3, Arkansas 1

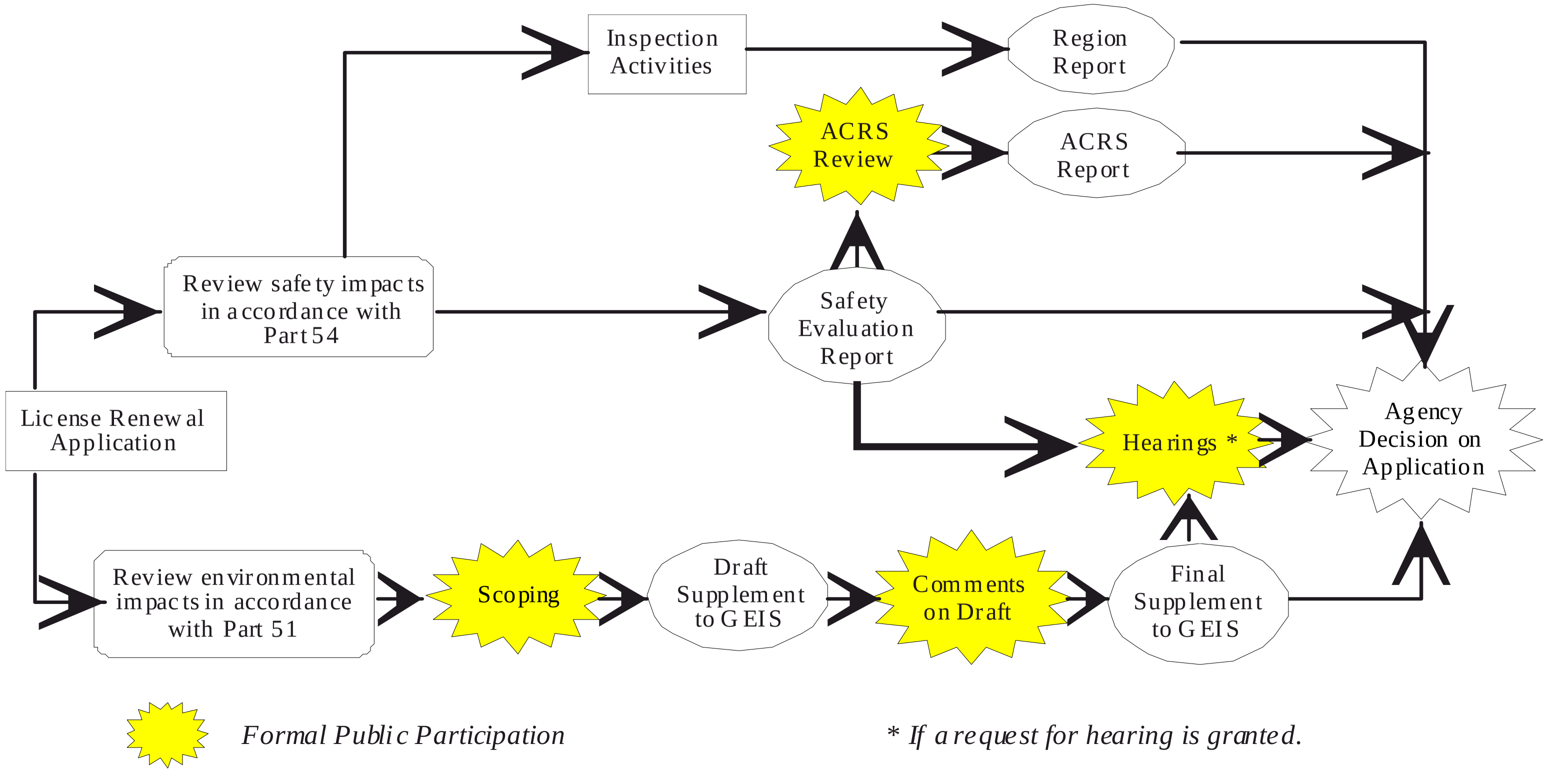
- **Application Submitted**
- Hatch 1&2, Turkey Point, Peach Bottom, North Anna, Surry, McGuire, Catawba

- **More Planned**
- FY02 – 6 announced (Including Point Beach 7/02)
- FY03 – 6 announced
- FY04 – 4 announced
- FY05 – 2 announced and 2 unannounced applications

LRA Preparation Process



NRC Approval Process



Note: Application considered timely after 30 day NRC sufficiency review is complete

Assessment Results

- License extension for 20 additional years is possible and economic
- Need to start project January 2002 to meet 5 year prior to license expiration timeliness criteria
- Infrastructure improvements needed to support scoping and screening
- Public and Government relations work in Minnesota needs to start now

Major Milestones

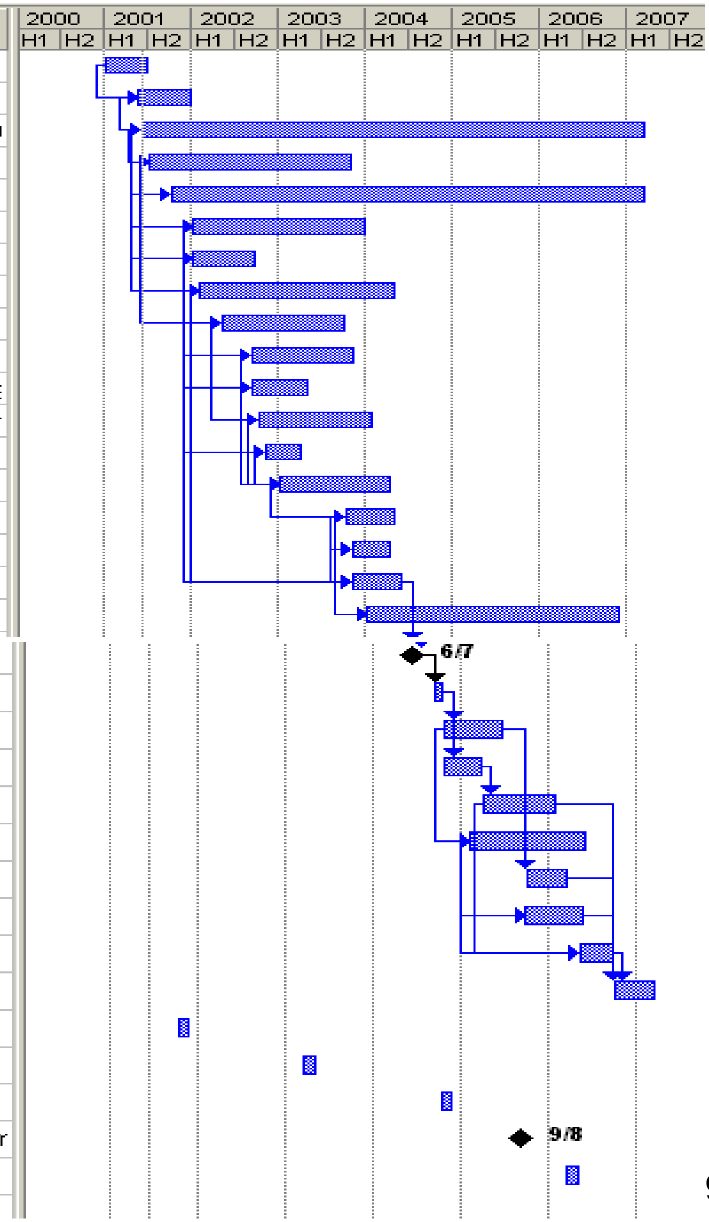
- 2001- Get Organized, Project and Budget Approval, Letter to NRC
- 2002- Information Tools, Databases, Procedures, Training
- 2003- Start LRA, Scoping/Screening, AMRs, AMPs, TLAAs, SAMA, EIS
- 2004- Complete IPA, LRA, EIS, USAR Supplement
  Submit LRA in September 2004
- 2005- NRC Review, RAIs, EIS Meeting, Start Implementation Effort
- 2006- ACRS/ASLB Hearings, SER Draft Issued
- 2007- Renewed License Expected by March 2007

Unique Considerations

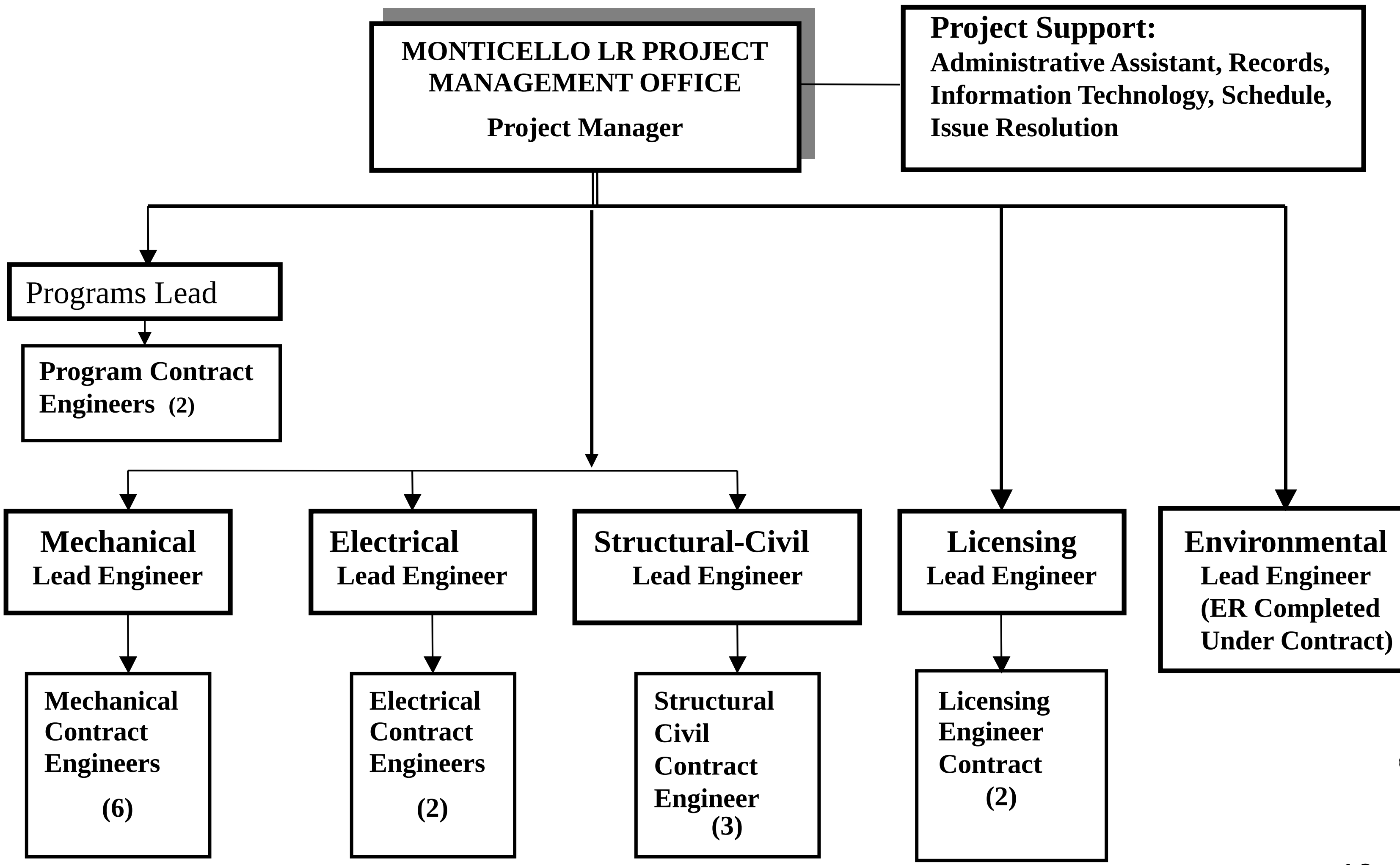
- Joint application with Duane Arnold and Prairie Island was considered, timing is not confluent
- Anticipate contested application or intervention
- Make use of new GALL and SRP-LR format
- Will utilize some information from previous LR work

Project Gantt Chart

	Task Name
1	Prepare LR Project Plan
2	LR Plan Approval
3	Project Mangement, Staffing, Training and Reportii
4	Establish Information Sources and Management T
5	Public Relations
6	Prepare LR Methodology and Procedures
7	Prepare LR Application Initial Draft
8	Prepare Environmental Report Supplement
9	Scoping
10	TLAA Identification and Evaluation
11	Identify and Review Plant Aging Management Proc
12	Identify Components Subject to Aging Managemer
13	Assemble Plant Operating Experience (thru 2002)
14	Component Aging Management Reviews
15	Scoping and IPA Final Reviews and Approvals
16	Prepare SAR Supplement
17	Assemble Final LR Application
18	Begin Early Implementation Tasks
19	LR Application Approval And Submittal
20	Regulatory Sufficiency Review
21	Application: Part 54 Reviews
22	Application: Part 51 Reviews
23	Regulatory Supplement to the GEIS
24	Safety Evaluation Report
25	Regulatory Site Inspection Activities
26	ACRS Reviews
27	ASLB Hearings
28	NRC Decision on Application
29	2001 Plant Refueling Outage
30	2003 Plant Refueling Outage
31	2004 Plant Refueling Outage
32	Prepare Decom Plan (If LRA Suff. Review Not Corr
33	2006 Plant Refueling Outage



Typical Project Organization Chart



Summary of Project Task Costs

Task	Task Description	Task Estimate
1	Prepare License Renewal (LR) Project Plan	$ 69,400
2	LR Plan Approval	$ 34,120
3	Project Management, Staffing, Training and Reporting	$ 902,250
4	Information Sources and Management Tools and Contingency	$ 5,661,840
5	Public Relations	$ 835,400
6	Prepare LR Methodology and Procedures	$ 288,120
7	Prepare LR Application Initial Draft	$ 248,240
8	Prepare Environmental Report Supplement	$ 849,280
9	Scoping	$ 348,500
10	TLAA Identification and Evaluation	$ 516,720
11	Identify and Review Plant Aging Management Programs	$ 82,980
12	Identify Components Subject to Aging Management Review	$ 368,480
13	Assemble Plant Operating Experience (thru 2002)	$ 20,580
14	Component Aging Management Reviews	$ 978,300
15	Scoping and IPA Final Reviews and Approvals	$ 85,940
16	Prepare SAR Supplement	$ 79,800
17	Assemble Final LR Application	$ 144,100
18	Begin Early Implementation Tasks	$ 55,800
19	LR Application Approval and Submittal	$ 120,900
20	Regulatory Sufficiency Review	$ 116,800
21	Application: Part 54 Reviews	$ 1,855,600
22	Application: Part 51 Reviews	$ 1,441,000
23	Regulatory Supplement to the GEIS	$ 240,200
24	Safety Evaluation Report	$ 292,000
25	Regulatory Site Inspections	$ 167,600
26	ACRS Reviews	$ 154,900
27	ASLB Hearings with Contingency	$ 1,457,800
28	NRC Decision on Application	$ 16,800
	Total Project Cost Estimate	**$ 17,433,450**

License Renewal Estimated Budget

- 2002 $3.5M
- 2003 $4.0M
- 2004 $4.0M
- 2005 $3.0M
- 2006 $2.0M
- 2007 $1.0M

Potential Long Term Capital Improvements

DESCRIPTION/OUTAGE	2009	2010	2011	2013	2015	ANNUAL	REMARKS
Spent Fuel Storage Costs-Plan for onsite storage as worst case cost impact for LR	15,000,000					5,000,000	$1M/Year to operate $4M/Year for Casks@$2M Each
Two Transformer Replacement	2,000,000		2,000,000				Main and 1AR
Refurbish CRD-HCU assemblies			5,000,000	5,000,000	5,000,000		Valves, accumulators, drives, solenoids
Rebuild/redesign of the main control room and obsolescence for I&C components	5,000,000	10,000,000	5,000,000	5,000,000	5,000,000		Includes digital upgrade of key systems
Inspect/repair or replace reactor vessel internals						1,000,000	BWR VIP program
Replace feedwater heaters (11-15)	1,000,000	1,000,000	2,000,000	2,000,000			#14, 15 and Coolers #11, 12
Evaluate main steam and feedwater piping and components for repair or replacement	500,000	1,500,000	1,000,000	500,000			
Simulator upgrades and improvements	1,000,000		1,000,000	1,000,000			
Replace inboard MSIVs			3,000,000				
Repair/refurbish/replace the underground circulating water piping	5,000,000		5,000,000	5,000,000			
Replace generator rotor, Rewind/refurbish generator stator	15,000,000						Rewinding and refurbishing is an alternative if the shaft is OK
Replace Recirc motors, new variable speed drive	7,000,000						
Cable replacement	10,000,000	15,000,000	10,000,000	10,000,000	15,000,000		8500 @5K, 4KV @$1.5M, I&C @$7M, $10M Undervessel cable
Recoating of Torus			2,500,000		2,500,000		Recoat Torus interior
4KV Breaker replacement	5,000,000			5,000,000			
Primary containment Bellows Replacement	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000		Assume 5 bellows need replacement
Recurring Annual Capital Budget						7,000,000	See Note 1 below for examples
Total	68,000,000	29,000,000	38,000,000	35,000,000	29,000,000	13,000,000	

Note 1) Examples of potential capital improvement items:

- Refurbish RWCU pumps, motors, Hx
- Replace Drywell coolers
- Refurbish/replace critical HVAC dampers and operators
- Refurbish the recirc suction and discharge valves, replace stems
- Replace the recirc pump shafts, impellers, motors
- Replace refueling and seal bellows carbon steel components
- Implement long term plans for safe end weld overlays or replacement
- CRD Stub tube UT inspection for IGSCC in HAZ of housing-to-stub tube welds
- Reactor Building Crane
- Replace and upgrade Battery cells
- Morris relicensing
- Feed Pump Motor and Pump Replacement
- Cooling Tower Repair
- Next Generation of Process Computer IT Improvements
- Replace RPV closure stud bolts refurbish and replace internals of the SRVs

Financial Analysis

- **Assumptions**
  - Capital improvement costs are as estimated (conservative)
  - On site fuel storage
  - Power rerate of 6% is achieved in 2007
  - Two year refueling cycles start 2003
  - O&M Escalates at 2.5%
  - Neglected carbon emission credits
  - License Renewal costs are capitalized
- **Benefits**
  - Increase asset value with 20 years additional operation
  - NPV= $161 million (Most conservative case, preliminary estimate)

Risks

- State of MN opposition- Moderate risk due to previous experience, risk improving with increasing future energy needs and Federal government support
- High Level Waste Issue-Moderate risk associated with DOE and PFS storage. Assumed onsite storage for financial analysis
- Continued Plant Safety- Low risk due to past record and current changes
- Community opposition-Low risk due to good community relations
- NRC Rejection of Application- Low risk since all plants that have applied have received acceptable sufficiency review
- Plant Economics- Low risk since financial analysis of capital costs are very conservative
- Corporate Economics- Financial risk of return on nuclear investment needs to be evaluated

Project Approval

- Meet with XCEL Officer sponsor- gain support
- XCEL plan to manage risks with State and Community
- Investment Review Council approval
- Board Of Directors approval by January 2002

NMC License Renewal Strategy and Plan

- NMC Goal
  – Achieve License Renewal for all NMC plants
- Benefits of NMC
  – Common data base
  – Common processes using Point Beach as model
  – Specialty resources available from NMC: material and environmental sciences

NMC License Renewal Strategy and Plan

- Point Beach to submit July 2002
- Monticello next NMC plant submit Sept 2004
- Palisades sent NRC letter January 2005
- Duane Arnold studying possibility of license renewal
- Prairie Island resolving spent fuel issues
- Kewaunee not currently interested

NMC License Renewal Strategy and Plan

- License Renewal Project Considerations
  - Project Manager should have LR experience
  - Three staffing options
    - Staffed by all utility personnel
    - Leads are utility personnel - remainder are contractors
    - Turnkey project - all personnel are contract personnel
  - Resources
    - Committed resources stay committed
    - Plant support necessary
  - Infrastructure quality key to LR success
    - Equipment database (Q-List)
    - CLB and records management
    - System drawings
    - Environmental data

Conclusion

- Time of is of the essence
- XCEL budget and project approval are required
- NMC experience and support will assure success

NMC
Committed to Nuclear Excellence

Monticello Nuclear Generating Plant

Potential Capital Expenditures Strategy

May 22th, 2003

Introduction

This strategy document was created with the goal to assist in estimating potential large capital projects that would be needed if the State of Minnesota decides to approve legislation that authorizes spent fuel legislation. This strategy document also included potential projects that would be required to support operation through a 20-year license renewal period. Some of these projects should be integrated to realize synergies with the potential for performing an extended power uprate project. Examples of these would be replacing transformers and performing generator rewinding to increase the capacity of these components to permit a higher power level.

Large capital projects were considered to be projects greater than $1,000,000. The Xcel Capital Project Summary Sheets were drafted and are attached to describe these potential projects. A cash flow summary is attached in an Excel spreadsheet at the end of this document.

Some of these projects have not been reviewed and approved by the Monticello Plant Health Committee and thus are preliminary.

Dry Fuel Storage Projects

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Spent Fuel Storage (Option 1)		Monticello NGP	$400,000	$16,925,000
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2006**	TBD	**TBD**

ESTIMATED CASH FLOW							
ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	2008
	$0	$400,000	$2,750,000	$2,900,000	$9,075,000	$1,800,000	650,000

DESCRIPTION:

The Spent Fuel Storage Project will determine the most cost-effective approach to provide additional spent fuel storage capacity at Monticello and then implement that approach. Additional spent fuel storage capacity will be required by 2007 in order to maintain full core off-load capability and will also be required to support the license renewal effort to operate the plant until 2030.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Additional spent fuel capacity will preserve full core off-load capability and support renewing the operating license of the plant for an additional 20 years which will provide an economical and clean source of generation for the extended period.

ALTERNATIVES:

1) Do nothing. This alternative would lead to plant shutdown in approximately 2013 when the spent fuel pool reaches its full capacity. (The plant’s current operating license expires on September 8, 2010.)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

TBD

ENVIRONMENTAL ISSUES:

If an Independent Spent Fuel Storage Installation (ISFSI) will be built, an environmental report will need to be prepared. The NRC will also need to prepare an Environmental Impact Statement (EIS) as part of their review.

ASSUMPTIONS/RISKS/OPEN ISSUES:

The resolution of the high level waste disposal issue at the national level is needed. It is uncertain when Private Fuel Storage (PFS) or Yucca Mountain will be available to receive spent fuel from Monticello.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Spent Fuel Storage (Option 2)		Monticello NGP	$0	$17,125,000
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2008**	TBD	**TBD**

ESTIMATED CASH FLOW							
ANNUAL	PREVIOUS YRS	2005	2006	2007	2008	2009	2010
	$0	$1,400,000	$3,750,000	$2,900,000	$9,075,000	$1,800,000	$650,000

DESCRIPTION:
Spent Fuel Storage (Option 2) is the same as Spent Fuel Storage (Option 1) with the exception of adding $1,000,000 in for a replacement rack in order to maintain full core offload until 2009 new fuel receipt. This addition of a new rack allows the Spent Fuel Storage (Option 1) to begin 2 years later.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Additional spent fuel capacity will preserve full core off-load capability and support renewing the operating license of the plant for an additional 20 years which will provide an economical and clean source of generation for the extended period.

ALTERNATIVES:

1) Do nothing.
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

TBD

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Still being determined.

Life Renewal and LCM Projects

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
License Renewal Phase II		Monticello NGP	$4,000,000	$17,584,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply NG	2001	2006	P. Burke	270015

ESTIMATED CASH FLOW							
ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	
	$750,000	4,000,000	4,334,000	4,250,000	4,250,000	N/A	

DESCRIPTION:

The license renewal project will perform the studies and analysis required by regulations in order to obtain a 20-year extension of the current operating license. The current operating license for Monticello expires on September 8th, 2010. The studies and analysis include a review of all plant equipment against scoping and screening criteria to identify aging effects and developing programs and plans for managing these aging effects for the extended period of operation. As part of the application an environmental report will be prepared to demonstrate no new or significant adverse environmental effect.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Extending the operating license of the plant for an additional 20 years will provide an economical and clean source of generation for the extended period of operation providing benefit to the ratepayer.

There is minimal risk with this project since the NRC has approved extensions for 10 units and approximately 16 more units have applications under review. The application process is well defined and describe in industry and NRC guidance documents. This project will follow these guidance documents and industry issues to assure successful application approval.

ALTERNATIVES:

1. Do nothing. This alternative would lead to plant shutdown and decommissioning on September 8th 2010 when the operating license expires.
2. Replace generating capacity after the license expires on September 8th 2010 with a different plant.

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

Initial conservative financial analysis shows the NPV of the plant increases from $191 million to $398 million based on a $25 MW price. This increase in NPV is greater than 10 times the capital costs.

ENVIRONMENTAL ISSUES:

An Environmental Report will be developed as part of the License Renewal Application. The NRC will also prepare an Environmental Impact Statement as part of their review. To date the NRC has approved license renewal applications and environmental reports for 10 units. It is not expected that Monticello will find any new or significant environmental effects that would prohibit approval of the license extension.

ASSUMPTIONS/RISKS/OPEN ISSUES:

The resolution of High Level Waste disposal issue as related to the 1994 Prairie Island state legislation needs resolution since it is uncertain if Private Fuels Storage or Yucca Mountain will be available to receive the spent fuel. Monticello will need fuel storage no later than 2010 for either continued operation of decommissioning.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Transformer Replacement	Monticello NGP	$0	$4,000,000

OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2011**	TBD	**TBD**

ESTIMATED CASH FLOW				
ANNUAL	PREVIOUS YRS	2007	2009	
	$0	$2,000,000	$2,000,000	

DESCRIPTION:
Replacement of the Main Transformer and the 1R Transformer to support operation for 20 more years. Potential synergies exist with an extended power uprate project. Xcel has recommended the Main Transformer be replaced to due its service life.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing.
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Static Excitation System		Monticello NGP	$0	$2,075,000
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2005**	TBD	**TBD**

ESTIMATED CASH FLOW						
ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007
	$0	-	$1,575,000	$500,000	-	-

DESCRIPTION:
The self-excitation of the generator should be replaced to support extended plant operation.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
HCU Refurbishment		Monticello NGP		
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2013**	TBD	**TBD**

ESTIMATED CASH FLOW			
ANNUAL	PREVIOUS YRS	2011	2013
	$0	$5,000,000	$5,000,000

DESCRIPTION:
The original units should be replaced with new units that are not susceptible to collet aging.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing.
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE	
Main Control Room Upgrades	Monticello NGP			
OPERATING CO	**DATE SUBMITTED**	**IN SERVICE DATE**	**PLANT CONTACT**	**JDE BU Number**
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$5,000,000	$10,000,000	$5,000,000	$5,000,000

DESCRIPTION:
Replace obsolete and aged equipment in the control room.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Replace Feedwater Heaters		Monticello NGP		
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**

ESTIMATED CASH FLOW					
ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$ 1,000,000	$ 1,000,000	$ 2,000,000	$2,000,000

DESCRIPTION:
Service life of feedwater heaters requires they be replaced to support the extended period of operation. There are 5 heaters in each of two trains of feedwater.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability and efficiency for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE	
Feedwater & Main Steam Pipe Replacement		Monticello NGP			
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number	
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**	
ESTIMATED CASH FLOW					
ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$ 500,000	$1,500,000	$1,000,000	$500,000

DESCRIPTION:
Replace portions of feedwater and main steam pipe that are susceptible to erosion and corrosion.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability and safety for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE	
Replace Underground Circ Pipe	Monticello NGP			
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$5,000,000	-	$5,000,000	$5,000,000

DESCRIPTION:
Replace buried pipe to assure function during the extended period of operation.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Recirculation Motor Variable Speed Drive		Monticello NGP		
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2009**	TBD	**TBD**

ESTIMATED CASH FLOW					
ANNUAL	PREVIOUS YRS	2009			
	$0	$ 7,000,000	-	-	-

DESCRIPTION:
Replace recirculation motor generator sets with a variable speed drive to reduce house load, increase reliability and reduce maintenance costs.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Power Cable Replacement		Monticello NGP		
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**

ESTIMATED CASH FLOW						
ANNUAL	PREVIOUS YRS	2009	2010	2011	2012	
	$0	$ 10,000,000	$ 15,000,000	$10,000,000	$10,000,000	

DESCRIPTION:
Replace aged cables to increase plant reliability.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE	
Torus Recoat	Monticello NGP			
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2011**	TBD	**TBD**

ESTIMATED CASH FLOW					
ANNUAL	PREVIOUS YRS	2007	2009	2011	
	$0		-	$2,500,000	-

DESCRIPTION:
Repaint torus interior to minimize torus wall corrosion due to contained water during the period of extended operation.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE	
4KV Breaker Replacement	Monticello NGP			
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**

ESTIMATED CASH FLOW					
ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$5,000,000	-	-	$5,000,000

DESCRIPTION:
Replace 4 KV breakers due to aging and wear.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Primary Containment Bellows Replacement		Monticello NGP		
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$1,500,000	$1,500,000	$1,500,000	$1,500,000

DESCRIPTION:
Replace primary containment bellows due to aging.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Under Vessel Cable Replacement		Monticello NGP	$10,000	$2,500,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP			S. Hammer	

ESTIMATED CASH FLOW							
ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	
		$10K	-	$2.5 M	-	-	

DESCRIPTION: This project will replace all under vessel cables associated with the Intermediate Range Monitors, Average Range Monitors, Source Range Monitors, CRD Position Indication and Control Rod Drives.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):
The existing cable has shown indications of age related insulation degradation. Some cables have failed and have been replaced on a case-by-case basis. For continued operation beyond 2010, all of the cabling should be replaced to ensure continued reliable operation.

Cables should be replaced during the 2005 outage when associated systems are not required. Cable is connected to equipment with multi-pin connectors and could be prefabricated. The work associated with replacing the cables is not high risk and could be accomplished during a planned outage.

ALTERNATIVES:
Replace cable on an as required basis.

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):
Cable failure could cause unplanned plant outages.

ENVIRONMENTAL ISSUES:
None

ASSUMPTIONS/RISKS/OPEN ISSUES:
Proposal (Frametome) to replace all cable is being considered.

Significant Life Cycle Issues

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Fuel Pool Clean-up		Monticello NGP	$2,000,000	$3,000,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2002	2003	S. Hammer	270015

ESTIMATED CASH FLOW							
ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	
	$0	$2,000K	$1,000K	-	-	-	

DESCRIPTION:
Removal of control rods and Local Power Range Monitors (LPRM's) from the fuel pool. This is the final disposition of capital items removed from service in the last 10 years plus.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):
Prior to the 2005 refueling outage the additional space is needed for the storage of control rods and LPRM's in the fuel pool. After the 2003 outage we will be at our maximum storage capacity. If we are unable to install new control rods in 2005 we would be unable to operate the plant.

Other factors to consider include:
-

ALTERNATIVES:

1. Do nothing and shut down.
2. This is a four-month project and could be moved slightly. This work is best performed during the late fall and winter for several reasons including road weight restrictions. This activity would have major detrimental affects if performed just prior to our March 2005 outage.
3. There are options to make less fuel pool space available. This is a not a cost effective option. Mobilization / Demobilization of the shipping contractor is very expensive. Shipping our generated waste when mobilized is the best-cost option.
4. For the sites operating cycle we feel it is best to mobilize in the fall of 2003 and complete shipping in early 2004. This also spreads the cash flow over two years.

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):
This is a cost project with a negative NPV.

ENVIRONMENTAL ISSUES:
This is High Level Waste Disposal. It is a very common industry practice without incident. The use of a contractor reduces risk because this is their expertise.

ASSUMPTIONS/RISKS/OPEN ISSUES: None

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Fire Protection System Upgrades		Monticello NGP	$1,420,000	$1,420,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2002	2003	S. Hammer	270015

ESTIMATED CASH FLOW							
ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	
	$0	$1,420K	-	-	-	-	

DESCRIPTION:
The Fire Protection Upgrade project will install new fire protection systems to meet NFPA regulations. This is a contingency capital project to address newly identified issues at Monticello. We are currently performing around the clock fire watch activities to meet requirements. We have identified several fire protection system upgrades that are capital activities. The activities are not completely defined at this time and preliminary engineering continues.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):
This project will satisfy NFPA code requirements and NRC commitments.

Other factors to consider include:

- We need to complete our preliminary engineering activities and determine our best-cost options for meeting code and eliminating fire watch activities.

ALTERNATIVES:

1. Do nothing and continue fire watches around the clock increasing Operating expenses.

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES: Still being determine.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE	
Refuel Bridge Replacement	Monticello NGP	$0	$1,500,000	
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2004**	TBD	**TBD**

ESTIMATED CASH FLOW							
ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	
	$0	$	$1,500,000	-	-	-	

DESCRIPTION:
The refueling bridge needs replacement due to aging and obsolescence.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Improve plant productivity while reducing outage risk and potential delays.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing this component could potentially lead to extended outage time due to bridge malfunctions. Other risks are still being determined.

Extended Power Uprate

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Extended Power Uprate		Monticello NGP	$0	$22,000,000
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2007**	TBD	**TBD**

ESTIMATED CASH FLOW							
ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	2009
	$0	$0	$1,000,000	$2,500,000	$3,500,000	$10,000,000	$5,000,000

DESCRIPTION:
Perform analysis and physical plant modifications to extend the power level up to at least 1880 Mwth. The power uprate project performed in 1996 performed many of the analysis at the 1880 Mwth power level. Additionally the GE topical reports provide the bases for extending power up to 120% of the license value or 2004 Mwth. One of the key aspects of this project would be to perform an optimization study, taking into consideration synergies with replacement of components for license renewal to determine the optimum power level.

Potential projects to support an uprate are: Upgrade turbine flow path, upgrade generator cooling and excitation, Upgrades to the feedwater system valves, and pumps and heaters.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):
Benefits of performing this project are to increase the plant output.

ALTERNATIVES:

1) Do nothing.
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

TBD- The financial benefit of extending the power level will be significant.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Appendix K – Power Uprate	Monticello NGP	$2,700,000	$2,700,000

OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2001	2003	S. Hammer	270015

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	
	$77,000	$2,623K	-	-	-	-	

DESCRIPTION: This project installs ultrasonic feedwater flow measuring equipment with improved accuracy resulting in higher plant capacity. 10CFR50 Appendix K allows plants to reduce their 2% power uncertainty factor by installing new technology flow measurement equipment with greater accuracy.

The ultrasonic flow measuring equipment proposed could reduce the current 2% uncertainty factor to 0.6% or less, supporting a subsequent power increase of 1.4% or more. A preliminary study of existing plant systems using the 1996 Rerate Project analysis indicates the sufficient margin exists to implement a power uprate of this kind.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):
Based on actual plant operating data, the projected increase in electrical output is 1.4% or 8.5 MWe.
$255K of annual capacity benefits
$336K of annual electric wholesale market revenues.
$613K of avoided energy purchases (ratepayer benefit, not included in financial model.)

Other factors to consider include:

- Project was preliminary funded in 2002 and deferred to 2003 due to capital funding availability.

ALTERNATIVES:

1. Do nothing. ($80K pre-construction funding moves to O&M)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):
Avoided Annual Capacity Purchases and Wholesale revenues $591K
NPV (including pass through fuel clause) -$366K
NPV (excluding pass through fuel clause $1,610K

ENVIRONMENTAL ISSUES:
None

ASSUMPTIONS/RISKS/OPEN ISSUES:
90% of the cost associated with equipment purchase is under firm contract.
Construction risk of cost overrun is minimal for this project due to small amount of work scope and simplicity of installation. The risk of not achieving the targeted increase in electrical output is low.

Annual General Capital Requirements

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Capital Projects <$1M		Monticello NGP		
OPERATING CO	DATE SUBMITTED	**IN SERVICE DATE**	**PLANT CONTACT**	JDE BU Number
Energy Supply – NSP	**2003**	**2012**	TBD	**TBD**

ESTIMATED CASH FLOW					
ANNUAL	PREVIOUS YRS	Annually			
	$0	$ 7,000,000	-	-	-

DESCRIPTION:
Example of annual capital projects are: Feed Pump Motor and Pump Replacement, Cooling Tower Repair, Replace Drywell coolers, CRD Stub tube UT inspection for IGSCC in HAZ of housing-to-stub tube welds, refurbish the recirculation suction and discharge valves and replace stems, replace RPV closure stud bolts refurbish, replace internals of the SRVs, implement long term plans for safe end weld overlays or replacement, replace refueling and seal bellows carbon steel components, replace the recirculation pump shafts, impellers, motors, replace and upgrade battery cells, and refurbish RWCU pumps, motors and Hx.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc.…):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

Project Summary	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
License Renewal	$ 3,963,455	$ 4,334,033	$ 4,250,000	$ 4,250,513						
Life Cycle Management Implementation										
Two Transformer Replacement					$ 2,000,000		$ 2,000,000			
Refurbish CRD-HCU assemblies									$ 5,000,000	$ 5,000,000
Rebuild/redesign of the main control room and obsolescence for I&C components							$ 5,000,000	$ 10,000,000	$ 5,000,000	$ 5,000,000
Replace feedwater heaters (11-15)							$ 1,000,000	$ 1,000,000	$ 2,000,000	$ 2,000,000
Evaluate main steam and feedwater piping and components for repair or replacement							$ 500,000	$ 1,500,000	$ 1,000,000	$ 500,000
Replace Under Vessel Cable			$ 2,500,000							
Repair/refurbish/replace the underground circulating water piping							$ 5,000,000		$ 5,000,000	$ 5,000,000
Replace generator rotor, Rewind/refurbish generator stator							$ 15,000,000			
Replace Recirc motors, new variable speed drive							$ 7,000,000			
Cable replacement							$ 10,000,000	$ 15,000,000	$ 10,000,000	$ 10,000,000
Recoating of Torus									$ 2,500,000	
4KV Breaker replacement							$ 5,000,000			$ 5,000,000
Primary containment Bellows Replacement							$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
Recurring Annual Capital Budget For LR	$ 7,000,000	$ 7,000,000	$ 7,000,000	$ 7,000,000	$ 7,000,000	$ 7,000,000	$ 7,000,000	$ 7,000,000	$ 7,000,000	$ 7,000,000
Spent Fuel Storage (Option 1)	$ 400,000	$ 2,750,000	$ 2,900,000	$ 9,075,000	$ 1,800,000	$ 650,000	$ 1,400,000	$ 650,000	$ 1,400,000	$ 650,000
Spent Fuel Storage (Option 2)			$ 1,400,000	$ 3,750,000	$ 2,900,000	$ 9,075,000	$ 1,800,000	$ 650,000	$ 1,400,000	$ 650,000
(Rerack $2,000,000 + ISFSI option 1)										
Power Uprate		$ 1,000,000	$ 2,500,000	$ 3,500,000	$ 10,000,000		$ 5,000,000			
Plant Health Committee Items										
Fire Protection Upgrades	$ 1,420,000									
Fuel Pool Cleanup	$ 2,000,000	$ 1,000,000								
Appendix K	$ 2,700,000									
Refuel Bridge Replacement		$ 1,500,000								
Static Excitation System		$ 1,575,000	$500,000							
Total (Less Spent Fuel Option 2)	$ 17,483,455	$ 19,159,033	$ 19,650,000	$ 23,825,000	$ 20,800,000	$ 7,650,000	$ 65,400,000	$ 36,650,000	$ 40,400,000	$ 41,650,000

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Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	021
Requestor:	Nancy Campbell, Chris Shaw & Steve Rakow		
Date Received:	December 10, 2013		

Question:

Reference: Testimony and Schedules of J.A. Stall pages 31 and 32 Mr. Stall indicates that Xcel should have known about the 13.8 kv since Xcel already had inadequate margins for its on-site electric distribution for Monticello prior to the LCM and EPU projects. Why didn't Xcel know about this need for the 13.8 kv distribution upgrade (from current 4 kv distribution) and why was this upgrade and related cost not included in the certificate of need?

Response:

The context for Mr. Stall's quote was probably not well described. The Company was aware of the need for adding capacity to its distribution system and the ultimate conclusion to move to the 13.8 kV upgrade was made in late 2007. The specific project was included in our Certificate of Need.

The question of how the Company decided on the 13.8 kV system requires context and understanding of the timing of certain decisions. In 2006 when the Program was first conceived, the Company knew it needed to do work on the internal electrical system. The internal debate that occurred in 2007 resulted in the decision to add new capacity to the system and to include two new 13.8 kV busses in the scope of the Program. By the end of 2007 that decision had been made and the Company included the 13.8 kV system in its conceptual plans. The Company could have added new capacity by adding new 4 kV busses but decided that 13.8 kV was a better choice for the reasons described in my Direct Testimony at pages 130-32.

Mr. Stall's testimony agrees that Xcel Energy reached the correct choice and that adding new 13.8 kV busses was a better outcome than adding new 4 kV busses at a discrete location. He points out that, at the present time, 13.8 kV is a more common voltage and, since it was necessary to add new capacity to the system, it was better to choose the 13.8 kV voltage. (Stall Direct Testimony, p. 57.)

Mr. Stall's criticism (pp. 31-32) merely pointed out that, in light of the existing demands on the internal electrical system coupled with expected increased electrical demands over the next 20 year, the need for added electrical distribution capacity was clear. From Mr. Stall's perspective, the need to add distribution capacity was obvious and did not require the type of vigorous debate that occurred at the Company.

From Mr. Stall's perspective, the existing internal distribution system allowed only minimal margin to prevent overloading the electrical busses. Since Monticello began operations in 1970, it added significant loads onto the original distribution system, including: (i) increased #11 and #12 RHR Pump Motors from 600 hp to 700 hp; (ii) added Emergency Filtration Train Building Loads – TMI Required Modification; (iii) Compressed Air Building Loads – Upgrade for Compressed Air System; and (iv) New Security Building Loads – NRC Security Requirement Changes from 9/11/01. Each of these additions took up some amount of the existing capacity on the system and eroded the remaining available margins.

By the time the LCM/EPU Program was proposed, the existing 4 kV system was operating at close to capacity already and the addition of any significant load would call for that capacity being expanded. Mr. Stall points out that, under normal plant conditions using the 4 kV system, Xcel Energy was experiencing under-voltage conditions when they would start large motors and pumps. The Company successfully managed this under-voltage situation by sequencing starting large and competing loads. Xcel Energy previously installed an under-voltage relay system that acted as a timer on the voltage excursions. Using that system, so long as an under-voltage event was resolved promptly it would not create any problems. However, if the under-voltage condition persisted it would ultimately result in a trip. While Xcel Energy successfully managed this situation, it was a clear signal that it was necessary to increase the margin in the electric system to avoid the need to use the under-voltage relay system.

Since one of Xcel Energy's goals was to position the plant for viable operations through 2030, it was important to address the electrical system since the existing 4 kV busses would not have been sufficient for the next 20 years under any reasonable circumstances. Adding new busses gave the plant room to expand electrical loads in the future as new requirements are imposed and new electrical loads implemented. In sum, Mr. Stall testifies that he did not see much need for the significant internal debate that occurred early in the project because the need for additional capacity was clear.

The question asks about how the 13.8 kV system was addressed in the 2008 Certificate of Need proceeding, Docket E-002/CN-08-185 (EPU Certificate of Need).[1] As noted above, in specific response to this question, the 13.8 kV system was included in the Certificate of Need Application and was specifically recognized in the Findings of Fact underlying the grant of our Certificate of Need.[2] With respect to the costs of the 13.8 kV upgrade, we estimated that although costs were not broken down by project, the $320-346 million initial estimate of costs modeled in the Certificate of Need also included amounts for anticipated electrical work. While the estimate was not broken down with specificity, approximately $20.9 million of the estimated total was for distribution system work. This estimate comes from our Supplemental Response to DOC IR 160, which is provided as Schedule 8, Table 2 of Mr. O'Connor's testimony. We provide a description of the development of that Supplemental Response in our answer to DOC IR 37. The Company ultimately obtained separate internal authorizations for the 13.8 kV system and believed that the cost would be in the $30 million range. While somewhat higher than the roughly $21 million attributable to distribution system work in our initial 2008 estimates, it was not viewed as a material deviation. Ultimately the cost of the 13.8 system was much higher for the reasons described in our filing.

Preparer:	Timothy J. O'Connor
Title:	Chief Nuclear Officer
Department:	Nuclear Operations
Telephone:	612-215-4613
Date:	December 24, 2013

[1] *Petition for a certificate of need for the Monticello Nuclear Generating Plant for Extended Power Uprate,* Docket No. E002/CN-08-185, ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT (Jan. 8, 2009).
[2] *Petition for a certificate of need for the Monticello Nuclear Generating Plant for Extended Power Uprate,* Docket No. E002/CN-08-185, FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION, ¶ 45 (Nov. 19, 2008).

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Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	83
Requestor:	Nancy Campbell		
Date Received:	April 16, 2014		

Question:

The following questions relate to the 13.8 kV Electrical Distribution System Modification Project described beginning on page 130 of Mr. O'Connor's direct testimony in Docket No. E002/CI-13-754:

a. Please provide the detailed original cost estimate of distribution upgrades needed for the LCM/EPU project, the final cost of the distribution upgrades and an explanation of the variances between the two.

b. Please provide a detailed analysis and timeline that shows how the cost of the 13.8 kV project increased from the original estimate to the final cost of $119.5 million.

c. Please provide all analyses, studies or other documents that describe the alternatives to implementing the 13.8 kV modification.

d. Please provide all analyses, studies and other documents that were used by Xcel management to approve the 13.8 kV project.

e. Please provide all analyses, presentations, slides or other materials developed for or used at the September 2007 "Electrical Summit" mentioned on page 131 of Mr. O'Connor's testimony.

f. On page 131, lines 17 – 18, Mr. O'Connor states "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 alternative." Please provide a copy of this analysis. Also, please provide the incremental additional cost in dollars.

g. Is Xcel aware of any other EPU projects that added a similar 13.8 kV system as part of the EPU? If yes, please provide the plant and cost of this modification.

h. On page 133, line 13, Mr. O'Connor states "We were implementing a first-of-its-kind system in a nuclear facility." Why was this first-of-its-kind facility necessary at Monticello and not at other nuclear plants implementing an EPU?

i. What was the original estimate for installation cost for distribution upgrades? What was the actual installation cost of the 13.8 kV distribution upgrade? Please explain the variance between the two.

j. On page 135, line 27 to page 136, line 1, Mr. O'Connor states "Such a course would have been just as costly." Please provide all analyses that support the statement that to modify the 4 kV system would have been just as costly as the 13.8 kV project.

k. On page 136, lines 6 – 9, Mr. O'Connor states "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." Is Mr. O'Connor stating that the 13.8 kV modification would have been required without the EPU project? Please provide all analyses that support this statement. Please provide any other nuclear plants that have implemented a similar project due to Fukushima and other reasonably anticipated requirements.

<u>Response:</u>

a.

Question: Please provide the detailed original cost estimate of distribution upgrades needed for the LCM/EPU project, the final cost of the distribution upgrades and an explanation of the variances between the two.

Response:
See response to part b. below.

b. *Question: Please provide a detailed analysis and timeline that shows how the cost of the 13.8 kV project increased from the original estimate to the final cost of $119.5 million.*

Response:

As previously explained, the 13.8 kV Distribution System was not part of the original estimate. However, the original budget for the 13.8 kV Distribution System was derived, in part, from originally budgeted costs for other systems that were part of the Monticello LCM/EPU Project. Per the 13.8 kV Distribution System NPA that was signed in December 2007, the projected budget for Distribution System modifications (as defined at that time) was $17.51 million. The budget was arrived at from two originally planned modifications, the 1R Transformer replacement (budget of $4.6 million) and the 4 kV breaker replacement (budget of $7 million). This resulted in an overall subproject budget increase of $5.91 million for detailed project development including Phase 2 engineering and the development of detailed cost estimates to allow implementation in the 2011 refueling outage. The engineering and design work was planned to be performed by GE and Shaw.

After the initial project planning was performed, the 13.8 kV Distribution System NPA was updated for budget year 2009, which estimated the total cost for the modification to be $33.10 million. The increase from the $17.51 million budget included costs to complete the full subproject including needed hardware purchases, additional GE costs, Phase 3 design work, installation and testing of the new system, accounting for required Recirculation System Motor-Generator ("MG") upgrades and refurbishments to allow for continued plant operation, and contingency costs. The 13.8 kV Distribution System budgeted costs are summarized in Table 1:

Table 1: 13.8 kV System – 2009 Budget

Description	Amount
Equipment	$11.1 MM
Design/Engineering	$4.0 MM
Installation	$11.5 MM
Project Management/Indirects	$1.6 MM
Plant Support/Administrative & General ("Overheads")	$2.3 MM
Contingency	$2.6 MM
Total	$33.1 MM

The final modification costs were $119.5 million, or $88.5 million over the original distribution system budget. The cost increases were identified in the subproject in three discrete time periods. First we identified the need to increase our initial estimate in June 2009 once our design engineering was well underway and long lead components were ordered. At that time we increased our estimate by approximately $15.59 million

We identified a second increase in our costs in December 2011 when we increased our authorization for the 13.8 kV work by approximately $35.7. This authorization followed the spring 2011 implementation outage and based on that experience we determined that the amount of time and costs associated with completing these highly complex task was higher than we expected in 2009.

In December 2012, we received additional information from Bechtel that led us to increase the total estimate of the 13.8 kV modification to $105.2 million. This estimate was based on completed detailed design and nearly complete work planning. These revised estimates were based on a detailed walk down of the plant by Bechtel's subcontractors and the cost to perform the installation increased significantly ($25.7 million) due to increased craft hours needed to install the complex equipment. We issued additional scope changes after the NPA was revised related to real time events occurring during the 13.8 kV distribution system implementation phase in the 2013 refueling outage.

- **Design/Engineering**. We incurred approximately $23.9 million in design and engineering costs. Our original scope for this modification was to maintain our existing 4kV distribution system and to perform minor equipment enhancements to support the Program. Throughout the design process we identified a number of obstacles for successful installation of the new 13.8 kV switchgear. In 2010 we identified that the transformers could not fit within the existing transformer footprints. We convened a 13.8 kV HIT team in January 2010 to evaluate all design considerations and project risks and determine a suitable modification plan. The HIT team identified viable options for location of the switchgear and presented recommendations to the Executive Committee in February 2010.

  We also incurred design/engineering costs to relocate our existing 'hot shop' equipment and to decontaminate the former hot shop to house the new 13.8 kV system. In converting the hot shop to the location for the new 13.8 kV system, we also required a new HVAC system with additional particulate filter capability to ensure the air and space were sufficiently clean to support this high voltage equipment. Finally, these costs related to the need to procure major components well advance of the final design completion. That required us to make additional design changes.

- **Materials/Components**. We incurred approximately $10.3 million in materials and component costs. These are the costs to acquire the materials and components necessary to complete the 13.8 kV modification. We encountered a few difficulties with certain of vendors and this led to the need to stop their work or reorganize our vendor relationships to better manage the work.

- **Installation**. We incurred approximately $73.2 million in installation costs. These costs are the costs to install the components and materials into the plant and turnover the new 13.8 kV system to operations. The primary reason that the installation costs were in excess of our original estimates was due to the difficulty and complexity of routing the new power and control cables throughout the plant. As one part of the process for routing these cables, it was necessary for us to build new pull boxes to prevent cable tension acceptance criteria from being exceeded. For the 2013 outage Bechtel estimated that installation of the 13.8 kV system would require over 59,000 hours (equivalent to 2,491 days) over 152 days. In addition, the testing process for the new 13.8 kV system required approximately three weeks to complete.

Questions:

c. Please provide all analyses, studies or other documents that describe the alternatives to implementing the 13.8 kV modification.

d. Please provide all analyses, studies and other documents that were used by Xcel management to approve the 13.8 kV project.

e. Please provide all analyses, presentations, slides or other materials developed for or used at the September 2007 "Electrical Summit" mentioned on page 131 of Mr. O'Connor's testimony.

Response:

See Attachment A-D, as well as previously produced documents that are responsive to these requests: NSP 0012792-97; NSP 0012798-803; NSP 0013308-10; NSP 0013293-97; NSP 0013278-83; NSP 001376-95.

f. *Question: On page 131, lines 17 – 18, Mr. O'Connor states "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 alternative." Please provide a copy of this analysis. Also, please provide the incremental additional cost in dollars.*

Response:
In September 2007, Xcel Energy convened an "Electrical Summit" to evaluate the options for accommodating the replacement reactor feed pumps and other new equipment. The Electrical Summit attendees included site personnel, and representatives from GE and Shaw.

We evaluated two primary electrical options for feasibility, cost, and schedule impact. The first option involved the replacement of the 1R transformer with a similar design, replacement of the 4 kV breakers with 3305 MVA breakers, and additional bus bracing. 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. Additional meetings with site management, GE and Shaw were held to evaluate cost and schedule information for the various options. Cost estimates provided by GE and Shaw indicated that the incremental additional cost associated with the 13.8 kV system was less than one percent over the new 4kV bus alternatives. Larger 8000 HP motors for RFP are typically designed to 6.9KV or 13.8KV due to the massive starting currents. 4kV systems are marginally capable of supporting the motor starting capability of the previous 6000 HP RFP motors. Ultimately, we concluded that a new 13.8 kV bus was the preferred option (over new 4kV or 6.9kV) based on these factors:

- *Comparability of modification and replacement cost estimates.* The estimated cost to modify and upgrade the existing 4 kV distribution system was essentially the same as the estimated cost to replace the 4 kV system;

- *Inadequate margin.* The original electrical distribution system was designed in the early to mid-1960s. The 4 kV system was no longer adequate to support operations, and created risk of trips. Absent an upgrade in the electrical system, motor trips or plant transients were likely to occur;

- *Obsolescence.* Evolving industry standards were causing other plants to upgrade original distribution system and the 4 kV system would have needed to be upgraded or replaced to support Monticello's extended operations;

- *GE opinion*. GE originally advised Xcel Energy that modification of the 4 kV system was feasible, but as planning progressed GE advised Xcel Energy that failure to implement the 13.8 kV system would place operating margins of the electrical distribution system at unacceptable levels.

g. *Question: Is Xcel aware of any other EPU projects that added a similar 13.8 kV system as part of the EPU? If yes, please provide the plant and cost of this modification.*

Response:
During the course of implementing the LCM/EPU, Xcel Energy benchmarked other EPU initiatives that were completed or in process. No other EPU undertaken in the United States has included the addition of a completely new 13.8 kV electrical distribution system. However, we note that the major contributor to cost was the location of the additional busses due to the space constraints at the Monticello site. This space constraint existed and would have impacted the implementation of this work, regardless of the voltage of the new busses.

As described at pages 58-60 of Mr. Arthur Stall's Direct Testimony, the decision to upgrade the electrical system in one comprehensive upgrade was more efficient than the piecemeal upgrades undertaken by the Santa Maria de Garona, a Spanish nuclear power plant owned by Iberdrola. Garona is Monticello's twin plant and uses Monticello's safety analysis for its design basis. Garona elected after twenty years of operation to follow a process of "continuous improvement," rather than major replacements for their life cycle management. In every refueling outage since 1983, Garona conducted stepwise changes and upgrades to its 4 kV system to justify continued operation beyond forty years. These resulted in 18 sequential modifications and upgrades to the 4 kV system, which were costly and difficult. In contrast, Monticello's upgrade to 13.8 kV dealt effectively with loads, safety, obsolescence, and reliability in one comprehensive upgrade. In Mr. Stall's professional opinion, adding the 13.8 kV system was a much better and more cost-effective choice than Garona's electrical upgrades.

h. *Question: On page 133, line 13, Mr. O'Connor states "We were implementing a first-of-its-kind system in a nuclear facility." Why was this first-of-its-kind facility necessary at Monticello and not at other nuclear plants implementing an EPU?*

Response:
No other EPU undertaken in the U.S. has included the addition of a new electrical distribution system because they had acceptable margin in their existing electrical distribution systems. Monticello did not have sufficient margin in its system to maintain safe and reliable operations over the course of its extended operating life.

The 13.8 kV system provided significant improvement in electrical system operating margin for critical reactor safeguard systems over the former 1960's plant design and equipment. Before the Project the plant operated with a 4 kV system, which allowed minimal margin to prevent overloading the electrical busses. This meant the plant was more likely to experience trips and additional equipment damage after a fault. The plant anticipated replacing the 4 kV components later in the plant's useful life. With the new 13.8 kV system, the plant has additional electrical margin on these busses and faces less risk of trips and forced outages. The increased margin has already provided real benefits. Xcel Energy eliminated existing margin concerns with the 4 kV system and provided additional breakers and margin for future loads.

Additionally, installation of the 13.8 kV system improved margins of plant equipment that remains on 4 kV breakers because condensate equipment that was formerly on the 4 kV system was taken off that system, thereby providing added margin for the equipment that remained. Finally, by moving the condensate pumps and motors to the 13.8 kV busses freed up capacity on the 4 kV busses so that the remaining equipment utilizing the 4 kV system would have additional margin for starts and safety considerations. This was particularly important as we retained the 4 kV system to operate important safety-related equipment such as the plant's station blackout requirement. Relieving the 4 kV system by moving electric demand to the new 13.8 kV busses had the net effect of improving margin for that equipment that remained at 4 kV.

i. *Question: What was the original estimate for installation cost for distribution upgrades? What was the actual installation cost of the 13.8 kV distribution upgrade? Please explain the variance between the two.*

Response:

See response to part b, above.

Overall, the installation of the 13.8 kV was much more difficult than we originally expected and resulted from the significant amounts of new cabling, cable trays and conduit that had to be routed around the plant. The overall complexity of the project created significant challenges in implementation and coordination with associated modifications.

The need to defer the 13.8 kV work scheduled for completion during the 2011 outage required additional craft execution, mobilization efforts, security contingency requirements and other costs. In June 2010, the Program team made an initial request to proceed with a split outage based on the scheduled outage length because of CapX2020, 13.8 kV interferences, and risks. In addition, late ECs for the 13.8 kV and Feedwater systems had delayed pre-outage work and milestones. Xcel Energy senior management made the decision to proceed with a split outage in June 2010. This decision allowed for additional time to complete the pre-outage work but also increased costs for the overall project.

In December 2012, Bechtel submitted a revised proposal to complete the 13.8 kV system installation. Based on a detailed walkdown with the recently prepared work packages and final design (June 2012) of the plant by Bechtel's contractors, the estimated cost to perform the installation increased significantly by more than $40 million due to increased craft hours necessary to install the complex equipment and addition of contingency.

j. *Question: On page 135, line 27 to page 136, line 1, Mr. O'Connor states "Such a course would have been just as costly." Please provide all analyses that support the statement that to modify the 4 kV system would have been just as costly as the 13.8 kV project.*

Response:
While complex, it was simpler and safer to install the 13.8 kV system rather than modify or replace the 4 kV system on a piece meal basis. The 4 kV system was not designed to be taken out of service at any time because it is required to operate 24/7 due to its support of safety-related equipment. If Xcel Energy had to modify or replace the 4 kV system, it would have had to build a redundant system (*i.e.*, separate busses) first to ensure continuity of service while it was constructing the new system. Such a course would have been highly inefficient and would not have resulted in the additional benefits arising

from the 13.8 kV system. Moreover, such a course would have been more complicated because of safety requirements.

We could have installed additional 4 kV busses. As described above and in the filing, however, doing so would not have achieved any better outcome and would have cost virtually the same as the 13.8 kV installations. Regardless of the selected voltage, we would have needed to locate the new equipment at a discrete location due to space constraints around the existing buss work. This means that we would have encountered the requirement to pull 14 miles of new cable either way. And either configuration would have required significant new equipment. In light of this, the decision was made to install the new distribution capacity at the higher and more robust voltage.

As such, it was more practical to install the 13.8 kV system as it could be constructed in parallel while the old system remained intact. And because the 13.8 kV system provided increased operating margins, portions of the 13.8 kV system – rather than the entire 4 kV system – could be taken out of service as plant conditions warrant. This improved plant flexibility. The complexity factors, along with the factors discussed in parts f. and h. above, were all part of the key decision making details that occurred during the electrical summit with Xcel Energy, General Electric, and industry experts in late 2007.

k. *Question: On page 136, lines 6 – 9, Mr. O'Connor states "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." Is Mr. O'Connor stating that the 13.8 kV modification would have been required without the EPU project? Please provide all analyses that support this statement. Please provide any other nuclear plants that have implemented a similar project due to Fukushima and other reasonably anticipated requirements.*

Response:
Yes, additional distribution capacity would have been necessary without the EPU to support the long-term viability of the plant for the duration of its extended license through 2030. The 4 kV system forced the plant to operate with minimal margins to prevent overloading the existing 4 kV electrical busses. These reduced margins increase the risk of trips and forced outages. We acknowledge that in 2007 (at the time the decision to install the 13.8 kV additions was made) a precipitating cause was the decision to support the larger pumps and motors. However, the need for additional distribution capacity to

run those pumps and motors did not change the fact that additional distribution capacity would be needed to support the long-term viability of the plant.
As new electrical loads could be anticipated during the next 20 years, it was clear that additional capacity would be needed regardless of the uprate. As noted above, the decision to install that capacity at the higher and more robust 13.8 kV voltage was roughly equivalent to the cost of adding additional 4 kV busses and breakers.

The following key electrical distribution requirements support the need for additional distribution capacity, irrespective of the uprate:

1. The 4 kV electrical buses were very close to maximum electrical fault ratings regardless whether the Company undertook the uprate. Bus #11 was less than 500 interrupting amps from its 4 kV maximum rating.

2. For life-cycle management purposes, the minimum distribution bus voltages during motor starting is required to be >80% nominal during starts. The existing 6000 hp motors caused voltage dipping to approximately 77% voltage during start. Adding additional electric demand to the existing distribution system would have exacerbated this problem.

3. Existing 1R transformer and 4 kV buses were near the limit of their capabilities in starting the existing motors regardless of whether the Company undertook the uprate.

4. We expect that upgrades that will be required by the NRC in response to the events at Fukushima will require additional distribution capacity and had we not installed the 13.8 kV system as part of our LCM/EPU Program, we would need to do so now. We recognize that additional electrical capacity will be needed to improve the plant's ability to withstand the loss of off site power, including additional capacity to increase outage durations, to improve our outage coping strategy, and to support additional on-site pumps and motors.

We are not aware of other U.S. nuclear plants with 4 kV systems with limited margin that required expansion of the distribution system to implement an uprate or such plants already had distribution systems in place that had sufficient margin to withstand new and anticipated loads. By contrast, at Monticello, the existing 4 kV system was being utilized at near full capacity. Further, the small footprint at Monticello limited the options available for installation of new bus work, regardless whether we upgraded to 13.8 kV or added additional 4 kV busses. In fact, had we chosen to add additional 4 kV busses, we would have had to install them in the same locations where we located the new 13.8 kV system, meaning that we would have encountered the same difficulties and costs either way.

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EPU Project/Electrical Meeting

Monticello Nuclear Generating Plant

Extended Power Uprate Project

Electrical Distribution Systems Meeting

September 18 – 19, 2007

Transformer Condition Monitoring

4 kV Offsite Transformers impacted by EPU

- 1R
- 1AR
- Both transformers (and the GSU) insured and monitored by NEIL

Transformer oil analysis standards

- Dissolved Gas Analysis (IEEE C57.104-1991)
- Insulating Oil Analysis (IEEE C57.106-1991)

1R Transformer Condition

1R Transformer Condition:

- 1R is a 33 MVA transformer placed in service in 1971
- **Dissolved Gas Analysis**:
  - Ethylene (C2H4) and sometimes Carbon Monoxide (CO) gases are in Condition II ("Greater than Normal")
    - Highest Ethylene sample 65 ppm, July sample at 45 ppm
    - IEEE Condition I is <50 ppm, NEIL Adverse Condition <55ppm
  - Ethylene and CO concentrations are **not increasing**
  - Monitoring will continue with monthly DGA samples
  - All other gases in Condition I or Normal Ranges

1R Transf. Condition (cont.)

- **<u>Insulating Oil analysis</u>**:
  - Dielectric Strength is lower than desired
    - Problems with previous tests
    - Re-tested at 35 kV by Predict Labs "Satisfactory for Continued Use, Continue Normal Operation"
    - IEEE recommends 45 kV, NEIL 40 kV
    - Low dielectric strength indicates impurities in Oil
    - Water, dirt, cellulose insulation or particulates
  - All other oil properties in Normal Range
  - Transformer has two (2) NEIL "Adverse Conditions"
    - Ethylene Concentration and Dielectric Strength
- Evaluate Processing Oil if not replaced in 2009 (If tank seals are adequate to allow vacuum processing of transformer oil)

1AR Transformer Condition

- 1AR has a 1950 Nameplate
- 1AR is a 7.5 MVA transformer with a separate external 13.8/13.8kV voltage regulator
- **<u>1AR transformer DGA analysis</u>**:
  - Dissolved gas levels are very Low
  - Transformer is energized, but normally unloaded
  - All gases are in Condition I or Normal Ranges

1AR Transf. Condition (cont.)

- **<u>1AR transformer Insulating Oil analysis</u>**:
  - Dielectric Strength is lower than desired
    - 20 kV (CSC), 16 kV (Predict Labs)
    - IEEE 34 kV, NEIL 30 kV
    - Why is 1AR dielectric strength low?
  - Transformer is relatively “wet” at 33 ppm water
    - IEEE 35 ppm, NEIL 39 ppm
    - 33 ppm water solubility limit is 8°C (46°F)
  - Interfacial Tension barely above NEIL Adverse Condition limit
    - 21.9 dynes/cm
    - IEEE 24 dynes/cm, NEIL 21 dynes/cm
    - Indicative of dissolved polar and oxidation products
  - Transformer has 1 NEIL “Adverse Condition,” Dielectric Strength

1AR Transf. Condition (cont.)

- 1AR is 57 years old, normal life is ~35-40 years
- 1AR Transformer Insulating Oil condition is below standards
  - Oil was reprocessed in 1990's
  - Cannot vacuum process oil – 1AR transformer not capable
  - Water is in the Oil -and- **Inside the Insulation**
  - Predict recommends, "Keep this unit under close observation" and "The oil may need reconditioning for further service."
  - John Anderson, Xcel OMES, "The oil tests keep looking more and more alarming"
- Integrity of transformer tank seals in question based on inability to keep moisture out

1AR Transf. Condition (cont.)

1AR Transformer and Voltage Regulator Replacement:

- Project Study was completed by S&L in 2006.
- Transformer lead times are long (approximately one year)
- 1AR replacement should be performed on line prior to 2009 EPU outage
  - TS 3.8.1 requires 2 off site circuits (2R and 1R)
  - TRM 3.8.1 requires 2 transmission lines
  - PRA Impact
  - MR Unavailability Impact
- Xcel Energy & NMC Systems Engineering recommend replacement
- Desire to have 1AR available to backfeed buses 13 and 14 when 1R is being replaced

4KV Switchgear Issues:

- Breakers' short circuit rating will be exceeded by EPU project
- Breakers are already identified for replacement by life cycle management plan
- Recent breaker stop failure when racking breaker into cubicle.
- Issues with assuring breaker racked in.
- Each breaker has its own personality/fit, i.e., floors and cubicles uneven
- GE Magne-blast cubicles are 23 ½ " wide, typical replacements 28-30" wide
- Outage installation window precludes complete replacement of switchgear lineup

Switchgear replacement goals

- Increase breaker and bus short circuit rating
- Upgrade breakers to last the remaining plant license life
- Make all switchgear cubicles identical so any breaker (of correct size) can fit into any cubicle.
- Ability to leave breakers in cubicle and racked out (i.e. seismic qualified in disconnect position)
- Desire additional spare breaker bus connections if possible. Only option for new 4KV load is A403 on Bus 14

Electrical Distribution Pinch Points

- Ability to start 2nd RFP without spuriously transferred PPS.
- Restore design margin and prevent reanalyzing degraded voltage transfer scheme. Address voltage drop from Bus #15/16 to LC103/104 and associated MCC's by removing no safety load from LC103/104 (MCC 131/141) (calc CA 93-066)
- Fault currents on #11 and #12 busses within breaker and bus rating when fed from 2R.
- Prevent new larger 1R transformer from creating issue with fault currents on 4160V buses
- Eliminate need for 2R (34kV) Rx/Clip fuses to limit fault current
- Eliminate requirement for an operator to increase 115KV voltage when on 1R prior to manually starting RFP.
- Eliminate 1R dependency on #10 XFMR and Auto LTC (115KV Voltage regulator). Allow plant to operate with 115kV (+/- 5%).

System Issues - EPU

- 1AR and voltage regulator replacement (pre-outage)
- 1R replacement
- 4160V breaker replacement and bus bracing, if needed
- 480V remove non-safety loads from LC 103 & 104 (MCCs 131 & 141 from essential buses)
- Update all plant AC electrical distribution system calculations when fed from 2R, 1R and 1AR for new EPU pumps, new 1R transformer, new 1AR transformer, new feedwater pump motors and all other EPU electrical load changes.

System Improvements

- EPU Modifications (“Register” status)
  - EC11445 - 4.16 KV SWITCHGEAR UPGRADE
  - EC11444 - 1R TRANSFORMER REPLACEMENT
  - EC11443 - ELECTRICAL SYSTEM ANALYSIS
  - EC00812 - EPU - REPLACE 1AR TRANSFORMER
- Modifications (“Register” status)
  - EC00817 - FORMALLY ABANDON 2R HYDRAN FAULT RECORDER – System Engineer wants upgraded replacement
- Implementation Dates
  - 2009 for EPU MODS (Spring 2009) and pre-outage mod for 1AR transformer (Fall 2008)

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Component	Operating Range
Buses 13-16	*4100 to 4400 V
Buses 11-12	3950 to 4400 V
1AR Transformer (unloaded)	*4225 to 4325 V
115 KV (Plant on 1R)	*116.0 to 121.0 KV See B.09.05-06 Figure 1
115 KV (Plant on 2R)	*114.7 to 121.0 KV (See NOTE below) See B.09.05-06 Figure 1
345 KV	*342 to 362 KV
2R Transformer (LTC in Auto)	4220 to 4320 V

Allow 115kV system to operate at 109 – 121kV (+/- 5%)

*(Reference NRC Commitments M83063A and M83012A)
NOTE: Cannot Re-start a RFP or Recirc. Pump with less than 116.0 KV in the event a 2R to 1R auto transfer occurs.

b. Voltages before and after pump starts should be monitored to assure that the operating ranges are maintained. A pump should not be started if insufficient voltage exists and cannot be raised. Past measurements have shown the following running pump voltage drops on the essential buses:

1) RHR Pump (600 hp) ~ 10.5 Volts

2) RHR SW Pump (700 hp) ~ 17.5 Volts

3) Core Spray (800 hp) ~ 25.0 Volts

If voltages cannot be maintained within the applicable levels, carry out procedures in Ops Man Section B.09.06-05. (Reference NRC Commitments M83063A and M83012A).

c. 1R and 2R Transformers and associated buswork into the plant are each capable of continuously supplying the entire plant load.

Questions

Draft B

Task Report T0600
Draft Revision B
August 2007

Project Task Report

Nuclear Management Company Monticello Nuclear Generating Plant Extended Power Uprate

Task T0600: Offsite AC Power System

Rev.	Prepared By	Date	Reviewed By	Approved By	Date
A	Joel Beres	7/27/07	See Passport AR 1078141		
B	William Hill	8/21/07	See Passport AR 1078141		

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Draft B

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R0 Draft B

REVISION SUMMARY

No.	Change
0	Original

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ACRONYMS AND ABBREVIATIONS

Item	Short Form	Description
1	A/E/Cs	Analyses/Evaluations/Calculations
2	AST	Alternate Source Term
3	BOP	Balance of Plant
4	BWR	Boiling Water Reactor
5	CLTP	Current Licensed Thermal Power
6	CPPU LTR	Constant Pressure Power Uprate Licensing Topical Report
7	EDG	Emergency Diesel Generator
8	ELTR	EPU Licensing Topical Report
9	EPU	Extended Power Uprate
10	LOOP	Loss of Offsite Power
11	LPU	Licensed Power Uprate
12	LTC	Load Tap Changer
13	LTR	Licensed Topical Report
14	MELLLA	Maximum Extended Load Line Limit Analysis
15	MELLLA+, M+	Maximum Extended Load Line Limit Analysis Plus
16	N/A	Not Applicable
17	NMC	Nuclear Management Company, LCC
18	NRC	Nuclear Regulatory Commission
19	OLTP	Original Licensed Thermal Power
20	RTP	Reactor Thermal Power
21	TPU	Target Power Uprate

1.0 SCOPE AND SUMMARY

1.1 Project Summary

Item	Parameter	Scope
1	Plant	Monticello Nuclear Generating Plant
2	Project	Extended Power Uprate (EPU)
3	Project Scope	Task T1500
4	Reactor Thermal Power Levels and Pressure	• Original Licensed Thermal Power (OLTP) of 1670 MWt • Current Licensed Thermal Power (CLTP) of 1775 MWt • Target Power Uprate (TPU) level of 2044 MWt • Licensed Power Uprate (LPU) level of 2004 MWt • No change in maximum normal operating reactor dome pressure of 1025 psia.

1.2 Task Scope

Item	Parameter	Scope
1	Task Number	T0600
2	Task Title	Offsite AC Power System
3	Task Evaluations	• 1R, 2R, and 1AR offsite sources • Offsite source associated equipment including switchgear, transformers, buses, cables, and instrumentation and control including non-safety related portions of bus transfers (e.g. 2R to 1R on fault detection) • Onsite AC System Task 0601 Boundary: the equipment boundary is the 4KV bus feeder breakers from the 1R, 2R and 1AR transformers. • EPU AC Load Studies for 1R, 2R, and 1AR Note 1: The scope of this task report does not include the individual effects of the various EPU modifications on the AC power system. These will be addressed by the MNGP modification process. This task report does address the overall effect of EPU AC modifications on the Offsite Power System. Note 2: Grid Stability under EPU conditions is included within the scope of task T0614, Grid Stability. Note 3: The adequacy of the main generator excitation and electrical

Item	Parameter	Scope
		protection/coordination will be addressed by task T0700, Turbine Generator Performance Evaluation. Note 4: The adequacy of the main transformer & bus duct cooling will be addressed in Task 0615, Main Transformer/Isophase Bus
4	Performance Improvement and OOS Options	• None

1.3 Results Summary

Item	Result	Summary
1	Key Evaluation Results	Key results within safety and design limits: • Under TPU conditions, the Offsite Power System has sufficient capacity to start and operate ECCS/LOCA plant loads • Under TPU conditions at the limiting offsite voltage, the Offsite Power System can start the largest in-plant motor load without initiating a degraded bus voltage transfer. • Under TPU conditions, the Offsite Power System provides power within the design voltage ranges of the connected AC electrical equipment. • Under TPU conditions the fault current contribution from the offsite sources is within the rating of the 4.16 KV breakers. • Under TPU conditions the loads are within the ratings of the offsite power supply electrical equipment
		Key results outside design limits: • None
		Other key evaluation results: • None
2	Impact on Other Tasks	• None
3	Direct Impact on Plant Configuration	• None
4	Impact on Design Operating Margins	• None
5	Implementation Recommendations	• None
6	Limitation of Performance Improvement and OOS Options	• None

1.3.1 Plant Specific Applicability to CLTR Generic Disposition

Item	CLTR Generic Scope	Applicability Assessment Parameter	Justification	Met
1	Per CPPU LTR Section 6.1: A specific analysis is required for the effect of increased power to non-safety related BOP loads at EPU on safety related loads. This can be accomplished by load studies for changes to non-safety related loads.	NA	EPU changes to BOP AC loads will require plant specific AC load studies	NA
2	Section 6.1 of CPPU LTR safety related loads are not significantly increased	Confirm in Task T0400, Containment System Response and Task T0407, ECCS-LOCA SAFER/GESTR	No change to ECCS equipment operating pressure or flow requirements under EPU conditions	Yes

1.4 Design and Licensing Bases

(MNGP USAR - Sections 8.1, 8.10, Appendix I, Appendix J.4)

The plant electrical power system is designed to provide a diversity of dependable power sources which are physically isolated so that any one failure affecting one source of supply will not propagate to alternate sources. The plant auxiliary electrical power systems are designed to provide electrical and physical independence and adequate power supplies for startup, operation, shutdown, and for other plant requirements which are important to safety. In the event of a loss or degradation of all off-site power sources, auxiliary power will be supplied from diesel generators located on the site. These power sources are physically independent from any normal power system. Each power source, up to the point of its connection to the auxiliary power bus, is capable of complete and rapid electrical isolation from any other sources. Loads important to plant safety are split and diversified between switchgear sections and means are provided for rapid location and isolation of system faults.

NRC Generic Letter 79-36, "Adequacy of Station Electrical Distribution System Voltages," required all addressees to analytically determine if offsite power systems and station electrical distribution systems were of sufficient capacity and capability to automatically start and operate in the event of an anticipated transient or accident. This letter also stated that protection of safety loads from under-voltage conditions must be designed to provide the required protection without causing voltages in excess of maximum voltage ratings of safety loads and without causing spurious separations of safety buses from off-site power.

Monticello's AC Load Study program controls and maintains the databases and computer models used to evaluate and record electrical load study cases and calculations that are performed. This program is utilized to assure that the distribution system voltage ranges meet the underlying electrical system design bases for plant conditions. The following loading conditions are analyzed to ensure that the electrical system design bases are maintained:

A. Full plant load
B. ECCS/LOCA plant load
C. Minimum plant load

The AC Load Study program has established the following electrical system design bases for determining acceptable distribution system voltages:

1. 120 VAC Instrument AC System Voltages:
Maximum - 132 VAC, Minimum - 108 VAC (+/– 10% of rated 120 VAC)

2. 480 VAC System Voltages:
Maximum - 506 VAC, Minimum - 426 VAC (+/– 10% voltage at the terminals of 460

VAC motors. Minimum voltage accounts for an additional 2.5% cable voltage drop from the MCCs to the load terminals.)

3. 4160 VAC System Voltage:
Maximum - 4400 VAC at the 4 KV motor terminals (110% of rated 4000 VAC).
Minimum - 3975 VAC (The degraded voltage relay setpoint was established based on 3897 VAC, with a bandwidth of +/– 18 VAC.

This determined the degraded voltage relay setpoint range of 3897 to 3933 VAC. The reset setpoint for the degraded voltage relay was established at 42 VAC greater than its dropout setpoint. If the degraded voltage relay is actuated following a motor start, system voltage will recover above 3933 + 42 = 3975 VAC within 9 (+/– 1) seconds. When the voltage recovers it will reset the degraded voltage relays such that a bus transfer will not occur. A separate analysis verifies that the bases for degraded voltage relay setpoint remains valid under the current configuration and loading conditions). Plant procedures incorporate these limits.

In support of the application which led to License Amendment 102, NSP performed load studies and stability analyses to demonstrate that electrical system voltages stay within equipment limits under new licensing basis conditions.

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2.0 REFERENCES

Item	Reference
1	1.1 "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate", NEDC-32424P-A, Class III, February 1999 (ELTR-1). 1.2 "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate", NEDC-32523P-A, Class III, February 2000 (ELTR-2). 1.3 "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate", NEDC-32523P-A, Class III, February 1999 (ELTR-2), Supplement 1, Volume I. 1.4 "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate", NEDC-32523P-A, Class III, April 1999 (ELTR-2), Supplement 1, Volume II. 1.5 "Constant Pressure Power Uprate", NEDC-33004P-A, Revision 4, Class III, July 2003. 1.6 Task Scoping Document, T0600 Offsite Power System, July 2007.
2	MNGP Technical Specifications Amendment 102
3	MWI-3-M-2.01 R11, AC Electrical Load Study (Load Case CA's identified herein)
4	OPS MAN B.09.06-05 R21, 4.16 KV Station Auxiliary, System Operation
5	CA 91-117 R0, Fuse Clip Sensor Trigger Level Analysis
6	OPS MAN B.09.06-01 R7, 4.16 KV Station Auxiliary, Function and General System Description
7	CA-97-089 R1, AC Voltage Study 2R to 1R Auto Transfer with LOCA Loading
8	Exhibit I to Letter from M. Hammer, NSP, to NRC, "Revision 1 to License Amendment Request dated July 26, 1996," dated December 4, 1997
9	CA-06-093 R0, 2R LTC and IAR Regulator Voltage Analysis
10	USAR Section 8.10 R 23, Adequacy of Station Electrical Distribution System Voltages
11	MWI-3-M-2.06 R5, Fuse/Breaker Coordination Study and Electrical Coordination

3.0 EVALUATION

A. General

The offsite power system provides AC power from the grid and distributes power to plant AC loads at the required voltages for load starting and steady state operation. It also provides instrumentation and control to transfer loads and to limit the effects of grid disturbances or system faults. EPU has the potential to cause changes to the grid and to the plant AC loads served by the Offsite Power System. The effect of these changes on design and performance requirements of the offsite power system is addressed herein.

The offsite power system at MNGP includes three separate sources of offsite power to safety related buses that are independent of back feeding through the unit transformer. In addition, the main generator at MNGP is not connected by a unit auxiliary transformer directly to the onsite power system, and consequently house loads do not require an auto-transfer to maintain power continuity in the event that the main generator output is interrupted or disconnected.

B. EPU Impact on Offsite Power System Grid Voltages

The offsite power system is designed to provide adequate power to site loads given that the steady state source 345KV and 115 kV grid voltages are within the ranges specified by OPS MAN B.09.06-05 R21 (Ref. 4) , which are derived from plant AC load studies. Operation within these ranges provides adequate voltage for operability of safety-related equipment, provides for proper operation of various automatic voltage regulating equipment such as load tap changers, and will result in the avoidance of inadvertent bus transfers of the safety-related buses due to degraded voltage when starting plant equipment. This performance is demonstrated by various analyses that assume grid voltages are within the operating ranges.

Task T0614, Grid Stability, determined that grid voltages remain with the ranges listed in Ref. 4. This includes post contingency voltages within the MNGP design bases for system failures.

C. Offsite Power System Loading and Performance at TPU conditions

Safety Related AC System Loads

At TPU conditions, there is no increase in the safety related AC loads. The Offsite Power System is designed to start and operate these loads for all design basis events. The AC load study includes safety related loads in the LOCA plant load model, which is the limiting AC loading design basis event. The 1AR offsite power source operation results in a load shed that separates non-safety related buses and MCCs from 1AR, thus EPU does not affect the loading of the 1AR offsite source or the 1AR transfer logic.

Non-safety Related AC System Loads

At TPU conditions, increased non-safety related loads affect the performance of the 1R and 2R sources in the Offsite Power System. The 1R and 2R sources are designed to carry the full plant load in addition to the ECCS/LOCA loads. Increased EPU loads are located on non-safety related buses 11, 12, 13, and 14. The increased EPU non-safety related loading resulted in a modification that replaced the existing 1R transformer with a new transformer with a significantly higher MVA rating and an automatic Load Tap Changer that is sized to accommodate the increase in the EPU non-safety related loads with adequate margin.

The increases in the continuous current associated with non-safety related loads operating under TPU conditions have been evaluated in accordance with the NMC modification process. The increases are within the design capacity and frame sizes of the affected bus electrical equipment and within the design ampacity of the motor feeder conductors while maintaining acceptable voltage drops on the feeder conductors.

The increase in the steady state load does not adversely affect the voltage regulation. The 1R modification evaluated the new 1R automatic load tap changer for the EPU load, and secondary 4kV voltages can be maintained within the ranges assumed by the AC load study for the design 115 KV ranges from no load to full load conditions. The existing 2R automatic LTC has significant bandwidth and the no load to full load 4KV voltages can be maintained within the ranges assumed by the AC load study. A recommendation to verify the 2RS voltage drop assumption in CA-06-093, 2R LTC and 1AR Regulator Voltage Analysis, is included herein. At TPU conditions, the 1AR loading does not change, and there are no changes to 1AR supply voltage ranges or to No. 10 autotransformer LTC operation, thus the 1AR voltage regulation is not affected by EPU. Note: EPU does not require a change to the no-load tap settings of 2RS and 1ARS.

At TPU conditions, AC load studies have been performed to demonstrate that the Offsite Power System (1R and 2R) is capable of starting and operating the non-safety related motor loads without resulting in a spurious degraded voltage essential bus transfer. Plant AC load studies have been performed and determined that the feed pump motors can be started without changes to the degraded bus voltage setpoint or time delay. In addition, calculations have demonstrated that the increased motor starting current, which includes a start of the feedwater pump motors at TPU conditions, will not result in a spurious activation of the 2R CLP fuse (NRC Commitment M-91051A).

EPU Coincident Plant Load and LOCA Loading

According to Section 8.10 of the MNGP USAR, The following loading conditions are analyzed to ensure that the electrical system design bases are maintained:

- Full plant load
- ECCS/LOCA plant load
- Minimum plant load (Note: The steady state minimum plant load is increasing at TPU conditions and the upper grid voltage ranges are not changing so that the margin to an overvoltage condition increases.)

The 1R and 2R sources are required to start and operate safety related LOCA loads coincident with full plant load.

Plant AC load studies have been performed that demonstrate that these two offsite power sources can start and operate the LOCA loads with the coincident TPU load. The limiting Core Spray Pump starting transient during a LOCA does not result in a spurious degraded voltage essential bus transfer from the 2R or 1R source. The Offsite Power System also continues to supply power within the design ranges of the AC electrical equipment. Thus the reliability and performance of the Offsite Power System during the design basis LOCA loading is maintained at TPU conditions.

Motor Short Circuit Contribution

In addition to voltage and steady state current performance, the larger pump motors result in an increase in the motor short circuit contribution. This increases the magnitude of the short circuit current seen by certain interrupting devices and by circuit breakers. Plant modifications, which included circuit breaker replacements with higher MVA ratings, have been made to the auxiliary electrical power system to accommodate the EPU increase in available short circuit current. AC System fault studies and fuse/breaker coordination studies have been performed in accordance with the MNGP modification process, and these studies demonstrate that selective coordination is maintained and that the affected plant electrical equipment is sized to safely interrupt the increase in the maximum available short circuit current. The 1R and 2R protective relaying is adequately designed for the changes in short circuit current. In addition, CA-91-117 (Ref. 5) has demonstrated that the current limiting reactor is adequately sized to limit the short circuit current within equipment ratings while operating on the 2R source at TPU operating conditions.

D. AC Load Study Assumptions

Various assumptions are included in the AC Electrical Load study (Ref. 3) regarding offsite system performance that are potentially impacted by EPU. The AC load study is described in the Updated Safety Analysis Report (Ref. 10) and references NRC review and approval correspondence. The relevant AC load study assumptions and the EPU impact are included below. The voltage regulation pre-start voltages and the source voltages are discussed in other sections herein.

- Loads shed by ECCS load shedding are not included in the Offsite AC System loading determination for the DBA LOCA loads.
  EPU Impact: EPU does not involve any changes to load shedding circuits.

- The AC load studies include minimum and maximum equipment voltages for steady state operation and motor starting.
  EPU Impact: EPU does not affect the voltage limits that plant equipment is designed for. These limits were established with NRC approval. All of the new EPU AC motors are designed to start and operate within the existing voltage limits.

- The Offsite AC System load application is based on ECCS load sequencing.
  EPU Impact: EPU does not affect any of the timing associated with ECCS load sequencing. Task T0407 ECCS-LOCA determined that there are no changes to the

sequencing and timing of AC ECCS loads during a DBA LOCA.

- The Demand and Diversity Factors for AC Load Studies are included in Appendix IV of Ref. 3
  EPU Impact: EPU does not require any changes to this load application methodology.

- Steady state voltage profile studies are completed using the maximum (Weak System) switchyard impedance with the minimum specified distribution system voltage. Short circuit studies use the minimum (Strong System) switchyard impedance with the maximum distribution system voltage.
  EPU Impact: EPU studies maintained these conservative assumptions that are not typically coincidental but serve to increase margin.

E. *Instrumentation and Control*

The load sequencing and load shedding associated with the DBA LOCA are not affected by the EPU. EPU does not involve an increase in the safety related electrical loads required to mitigate the LOCA event. The increase in non-safety related loads such as feedwater and condensate system loads does not require any additional load shedding for the 2R or 1R source to provide adequate power to safety related loads during a LOCA, and Task T0407 determined that there are no changes to the sequencing and timing of AC ECCS loads during a DBA LOCA.

Load sequencing and shedding also occurs for the 1AR source. No changes are required for these sources for an ECCS initiation under TPU conditions.

The 2R to 1R source transfer is described in Section C.2 of Ref. 6. The 2R to 1R transfer logic has been evaluated within the modification that replaced the 1R transformer, and no changes are necessary to the protective relaying, load shedding, and initiating conditions associated with this transfer. The 1R capability to provide power for plant shutdown has been verified by calculation (Ref. 7), which includes capacity for the inrush from the No. 11 Reactor Feedwater pump motor.

Task T0611, Appendix R Fire Protection determined that EPU does not involve any changes in the AC loads postulated to operate during an Appendix R event. Thus the DBA LOCA loading remains the bounding design basis event AC load case for the Offsite Power System at TPU conditions. Note that the design basis Appendix R event includes an assumption that the offsite power is unavailable

Under TPU conditions, there are no changes to the operation or setpoints for the degraded bus voltage and loss of voltage logic.

3.1 Methodology

Item	Evaluation Method	Task Application
1	NRC approved or accepted method (including level 2 computer codes)	• CLTR, Reference 1.5

Item	Evaluation Method	Task Application
2	Level 2 computer code not approved by NRC	• None
3	Non Level 2 numerical analysis	• None
4	Qualitative method	• None

3.2 Input and Assumptions

3.2.1 Key Inputs

Item	Parameter	EPU Value	Units	Ref. /Basis
1	None			

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3.2.2 Key Assumptions

Item	Assumption	Ref./Basis
1	115 KV and 345 KV grid voltages remain within the ranges listed in Ref. 4. This includes post contingency voltages within the MNGP design bases for system failures.	Task T0614, Grid Stability
2	No changes in ECCS pump horsepower requirements for short and long term DBA LOCA cooling	Tasks T0400, Containment System Response & T0407 ECCS-LOCA SAFER/GESTR
3	At TPU conditions, AC load studies have been performed to demonstrate that the Offsite Power System is capable of starting and operating the increased non-safety related loads without resulting in a degraded bus voltage or essential bus voltage transfer and without a change to the degraded bus voltage setpoint or time delay.	NMC Internal AC Electrical Load Studies per Ref. 3
4	AC System fault studies and fuse/breaker coordination studies have been performed at TPU conditions, and these studies demonstrate that selective coordination is maintained and that equipment is sized to safely interrupt the increased short circuit current.	NMC Internal AC System Fault Studies and Fuse/Breaker Coordination Studies per Ref 3 & 11
5	There are no changes to the required AC loads that are postulated to operate during an Appendix R event.	T0611 Appendix R/Fire Protection
6	The increase in the continuous current associated with loads operating under TPU conditions are within the design capacity and frame sizes of the affected bus electrical equipment and within the design ampacity of the motor feeder conductors while maintaining acceptable voltage drops on the feeder conductors.	AC Electrical Load Studies per Ref 3 which requires updates by the NMC modification process
7	EPU does not involve any changes in the AC loads associated with the mitigation of an Appendix R event	Task T0611, Appendix R Fire Protection
8	There are no changes to the sequencing and timing of AC ECCS loads during a DBA LOCA.	Task T0407 ECCS-LOCA
9	Existing CLP Fuse Settings and 2R-1R Transfer scheme are acceptable at TPU conditions	NMC Revisions to calculations CA-91-117 R0 and CA-97-089 R1

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Item	Assumption	Ref./Basis
10	Confirm no changes to the No. 10 Transformer LTC Operation at TPU conditions	AC Electrical Load Studies per Ref 3
11	The 1R modification evaluated the new automatic 1R load tap changer for the EPU load, and secondary 4kV voltages can be maintained within the ranges assumed by the AC load study for the available 115 KV supply voltages ranges from full load to no load conditions.	1R Modification

3.3 Results

Under TPU conditions, the Offsite Power System has sufficient capacity to start and operate the required safety related AC loads that are postulated to operate during design basis events. The capacity of the offsite sources is such that a degraded bus voltage transfer will not occur for the limiting design basis load cases.

Under TPU conditions, the Offsite Power System continues to supply equipment voltages within the existing design ranges for starting and steady state operation of AC electrical equipment.

Under TPU conditions, selective coordination is maintained, and steady state currents and fault currents are within the design ratings of the AC electrical equipment.

3.3.1 Key Results

Item	Parameter	Pre-EPU Value	LPU Value	Basis
1	Degraded Bus Voltage Setpoint (reset)	4kV bus voltage recovers to 3975V within 9 ± 1 seconds after a motor start for the bounding load study cases	4 kV bus voltage recovers to 3975V within 9 ± 1 seconds after a motor start for the bounding load study cases	EPU AC Load Studies

3.3.2 Supporting Evaluations

Item	Subject	Description/Basis
1		

3.4 Recommendations and Observations

3.4.1 Recommendations

Item	Subject	Recommendation
1	CA 91-117 R0, Fuse CLIP Sensor Trigger Level Analysis	Needs revision to reflect EPU feedwater pump motors (and existing 700 hp RHR motors)
2	CA-97-089 R1, AC Voltage Study 2R to 1R Auto Transfer with LOCA Loading	Needs revision to reflect EPU feedwater pump motors (and existing RHR 700 hp motors)
3	CA-06-093 R0, 2R LTC and 1AR Regulator Voltage Analysis	Obtain 2RS voltage drop data at TPU conditions to determine whether the 2R LTC bandwidth is adequate. Perform a minor calculation revision if necessary.
4	1R Transformer	Replace 1R transformer with a unit having a higher MVA rating and an automatic Load Tap Changer. Included with this change the adequacy of the 2R to 1R open transfer should be assessed.
5	4 KV Buses	The MVA ratings for the station 4.16KV breakers and bus work should be increased for EPU

Item	Subject	Recommendation
6	Electrical Load Study MWI-3-M-2.01 R11	Revise the following electrical load study cases: CA 91-067, 1R XFMR, Full Plant Load, CS Pump Starting CA 91-069, 1R XFMR, LOCA Load 2 CS Pumps Starting CA 91-071, 1R XFMR, Minimum Load CA 91-072, 1R XFMR, Full Plant Load, #11 FWP Starting CA 93-066, 1R XFMR, Degraded Voltage Setpoint, LOCA Load plus 2 CS Pumps Running CA 91-073, 2R XFMR, Reactor Bypassed, Full Load 2 CS Pumps Starting CA 91-075, 2R XFMR, Reactor Bypassed, LOCA Load, 2 CS Pumps Starting CA 91-077, 2R XFMR, Reactor Bypassed, Minimum Plant Load CA 91-078, 2R XFMR, Reactor Bypassed, Full Load, #11 FWP Starting CA 91-079, 2R XFMR, Reactor In-line, Full Load 2 CS Pumps Starting CA 91-081, 2R XFMR, Reactor In-line, LOCA Load, 2 CS Pumps Starting CA 91-083, 2R XFMR, Reactor In-line, Min. Plant Load CA 91-084, 2R XFMR, Reactor In-line, Full Load, #11 FWP Starting CA 91-085, 2R, Reactor In-line, Clip Trip, Full Load, 2CS Pumps Running CA 91-086, 1AR/10TR, LOCA Load, 2 CS Pumps Starting CA 91-087, 1AR/1ARS, LOCA Load, 2 CS Pumps Starting CA 91-090, 1R In Service (fault) CA 91-091, 2R, Reactor Bypassed (fault) CA 91-092, 2R, Reactor In-line (fault) CA 91-093, 1AR & # 10 XFMR (fault) CA 91-094, 1AR & 1ARS (fault)

3.4.2 Observations

Item	Subject	Observation
1	None	

Notes From the 9/18 & 19 Meeting

Options - Switch gear

1. Add 13.8KV busses for the RFPs.
2. Replace bus 11 & 12 switchgear with 500 MVA gear.
3. New 13.8KV bus with a feed from 1R and from an existing 13.8KV line.(minimizes the length of a 13.8KV underground run)
    - Could use a future change to 2R for second source.
    - Adds new 13.8KV busses for RFPs only with a future option to add the Recirc. MG sets.
    - Allows moving the new Condensate pump motors to busses 11 & 12.

Options –Transformers

1. Replace 1R with 2 -two winding transformers (2 winding transformers may have shorter lead time)
2. Replace 1R with a similar 3 winding transformer in 2011 (better fit with existing pad).
3. Replace 1R and 2R with new 2 winding transformers to feed the new 13.8KV bus and the existing 4KV busses.

Cost Buildup for 2 and 1 Above (Option 2) **$2.5M**

Item	New cost	Marginal Addition
4KV Switchgear busses 11&12	$500K	
1R1		-$500K
1R2		-$500K
Breaker Replacement	$1,500K	
Enclosure	$100K	
HVAC	$100K	
Foundation	$150K	
Cable	$150K	
Switch gear Bracing	$1,000K	
Total	$3,500	-$1,000

Issues:

1. Still starting the RFP motors at 4KV
2. Does not address 2R for LCM.

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Cost Buildup for 1 and 3 Above (Option5) $4M

Item	New Cost	Marginal Addition
1R1		-$500K
1R2		-$500K
2R1	$1,000	
2R2	$1,000	
13.8KV Switchgear	$600	
Cond. Pump Motor		------
RFP Motor		$100K
Recirc MG Set Motor	$1,200	
Foundations	$400K	
Switchgear Bldg.	$100K	
Cable	$500K	
HVAC	$100K	
Total	$4,900K	-$900K

Issues: Does not improve 4KV switchgear.

Costs/ Issues

Equipment	GE/SS&W
Installation/ Implementation	MNGP
Outage Impact	MNGP
Avoided future LCM costs	MNGP
Feasability of 2009 implementation	All
PRA impact	MNGP
Design Time Line	GE/SS&W

Approach

Pre-outage 2009

1. Remove 1R from service and remove from pad (note, must have 1AR in service)
2. Install 13.8KV and 480V switchgear, cables and conduit as much as possible.
3. Install new foundations, fire protection, oil containments etc. for new 1R1 and 1R2
4. Install transformer secondary cables/bus work for 1R1 and 1R2.
5. Plant computer tie ins.

Outage

1. Complete installation of 1R1 and 2 transformers
2. Replace RFPs and motors and tie into new bus
3. Replace Condensate pumps and motors and tie into new bus
4. Replace recirc. MG Set motors and tie into new bus.
5. Test switchgear
6. Remove 2R from service and install new 2R1 and 2?
7. Complete 13.8KV raceways and control circuits
8. Control room modifications
9. Simulator modifications

Actions Required

1. Preliminary Equipment Specs (Jack&Jay)
   - 1R1&2 Rating, Impedance,
   - 2R1&2 Cost & Delivery
   - 13.8KV Switch gear
     - NEMA 3R walk in switchgear
     - Double ended 7Bkrs./side
   - 480V switchgear NEMA
2. Cond. and RFP motor availability (Rod & Jay)
3. Recirc. MG Set motor Rating and availability (Jay)
4. Installation Equipment
   - 13.8KV, 4KV and control Cable (Jack & Dave)
   - Conduit/ trays (swgr to load) (Frank)
   - Duct banks (Xformer to Bldg) (Frank)
   - MCR and Simulator work (Frank)
   - Swgr Bldg (HVAC, Power etc.) Propose walk in Swgr.
5. Validate time to refurbish the existing 4160 busses (Rod)

Design Timeline & Costs	Priority
System Analysis	
Preliminary (3 days)	1
Final	1
Transformer sizing calc.	2
Switchgear and cable sizing calcs	5
Procurement specs	
Transformer	2
13.8 swgr	5
480V load center	5
Recirc Motors	3
RFP & Cond Motors	4
Protection Calcs	
Mod package development	
Xformer	4

Switchgear	3
Cond & RFP Updates	?
Recirc Motors	1

Parking Lot

1. Reposition 1AR
2. Impact of 109-121 KV Range
3. Expand listing of suppliers for 1R transformer to improve delivery.
4. Alternatives to LTC
5. Use of digital relays.

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Option 1: Add 13.8kV buses for Rx FW Pump Feeds (original study option 1), two separate 13.8kV feeds from T&D switchyard

Pros:

- Off loads existing system by removing reactor feed pumps from existing 4160V system
- Maximum electrical system capacity for future growth
- No need to upgrade 4160V buses from 250MVA to 350MVA
- We can move the condensate pump motors to buses 11 and 12.
- New feed from 13.8kV can be used for new 480V transformer feeds.
- Eliminates need to replace 1R transformer
- Most of the electrical installation can be installed prior to the 2009 outage.
- The starting of the reactor feed water pump motor no longer is a concern for offsite voltage.

Cons:

- Cost of two underground 13.8kV cable feeds from switchyard to NW corner of plant. (Approx. $2M)
- Can we make a new 13.2kV motor fit in feed pump room since it is longer than existing motors?
- Does not add voltage control for existing 1R sources. This does not improve the voltage range for the 115kV system required for Monticello plant.
- Adds complexity of electrical operation for plant Ops staff.
- Need to find a location to install the new 13.8kV and 480V buses and the 13.8kV/480V transformer.
- New equipment requiring maintenance and operations department training.
- Does not resolve aging 4160V switchgear

Option 2: Upgrade Bus 11 & 12 switchgear with 500MVA, 4160V switchgear in 2009 and rest in future outages and two 2 winding 1R transformers each 115/4.16kV

Pros:

- Resolves the 1R life cycle concerns
- Resolves switchgear for buses 11 and 12.
- Allows delay of switchgear 13 – 16 breaker replacements. Can replace breakers with like for like with some perform online.
- Least impact to present operation of the plant.
- Cost of two transformers may be less than a special design three winding transformers.
- Better lead time on the two winding transformers (industry standard transformer)
- Can put new transformers outside the "Protected Area" and construct prior to the outage. (Can also put new 1AR transformer in this same new area.)

Cons:

- Potential voltage issues when starting the large motors (Rx Feed Pump) with less than 80% during across the line start. Impact on other plant equipment during start.
- Need to reconfigure the 1R transformer foundation, oil containment and fire walls (or find alternative locations for new transformers)
- Increase cost to relocate security fence to enclose new equipment (and possibly require guard BRE post to be relocated)

Option 3: 13.8kV with feed from 1R and existing 13.8kV line with new 1R with 115/13.8kV and 115kV/4.16kV two winding transformers with tap changer on each transformer. Reactor recirc pump MG set motors need to be replaced as 13.2kV motors.

Pros:

- Off loads existing system by removing reactor feed pumps from existing 4160V system
- Maximum electrical system capacity for future growth
- No need to upgrade 4160V buses from 250MVA to 350MVA
- New feed from 13.8kV can be used for new 480V transformer feeds.
- Most of the electrical installation can be installed prior to the 2009 outage.
- The starting of the reactor feed water pump motor no longer is a concern for offsite voltage.
- Provides space for four breakers where existing buses 11 and 12 presently are located.
- Adds voltage control for existing 1R sources. This improves the voltage range for the 115kV system required for Monticello plant.
- Resolves life cycle concerns for transformer 1R

Cons:

- Cost of one underground 13.8kV cable feed from switchyard to NW corner of plant. (Approx. $1M)
- Reactor recirc pump MG set motors need to be replaced as 13.2kV motors. (or move condensate pump motors to new 13.2kV bus and move recirc MG motors to buses 13 and 14)
- Can we make a new 13.2kV motor fit in feed pump room since it is longer than existing motors?
- Adds complexity of electrical operation for plant Ops staff.
- Need to find a location to install the new 13.8kV and 480V buses and the 13.8kV/480V transformer.
- New equipment requiring maintenance and operations department training.
- New foundation, oil containment and fire walls for transformers
- Does not resolve aging 4160V switchgear

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Option 4: new 3 winding 1R with installation and 500MVA switchgear for buses 11 and 12

Pros:

- Minimum space constraint ***assuming it will fit in existing transformer bay***.
- Delay replacement of buses 13 – 16 until future outages
- Can re-use transformer foundation and oil containment
- Least impact to present operation of the plant.
- Could replace transformer after 2009 outage while plant is online.
- Least construction cost with greatest use of existing 4160V buses and cables.

Cons:

- May not be able to procure 1R for 2009 outage
- Availability of LV tap changers on 4.16kV windings is questionable
- Relatively unique transformer that would be hard to replace if it failed (same as present configuration)
- Potential voltage issues when starting the large motors (Rx Feed Pump) with less than 80% during across the line start. Impact on other plant equipment during start.
- The 3 winding transformer is high cost. May be as high as $3 to 4M.

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Option 5: New 1R and new 2R transformers with 115/13.8kV and 115kV/4.16kV two winding transformers with tap changer on each transformer. Reactor Recirc pump MG set motors need to be replaced as 13.2kV motors. Also make the new condensate pump motors 13.2kV.

Pros:

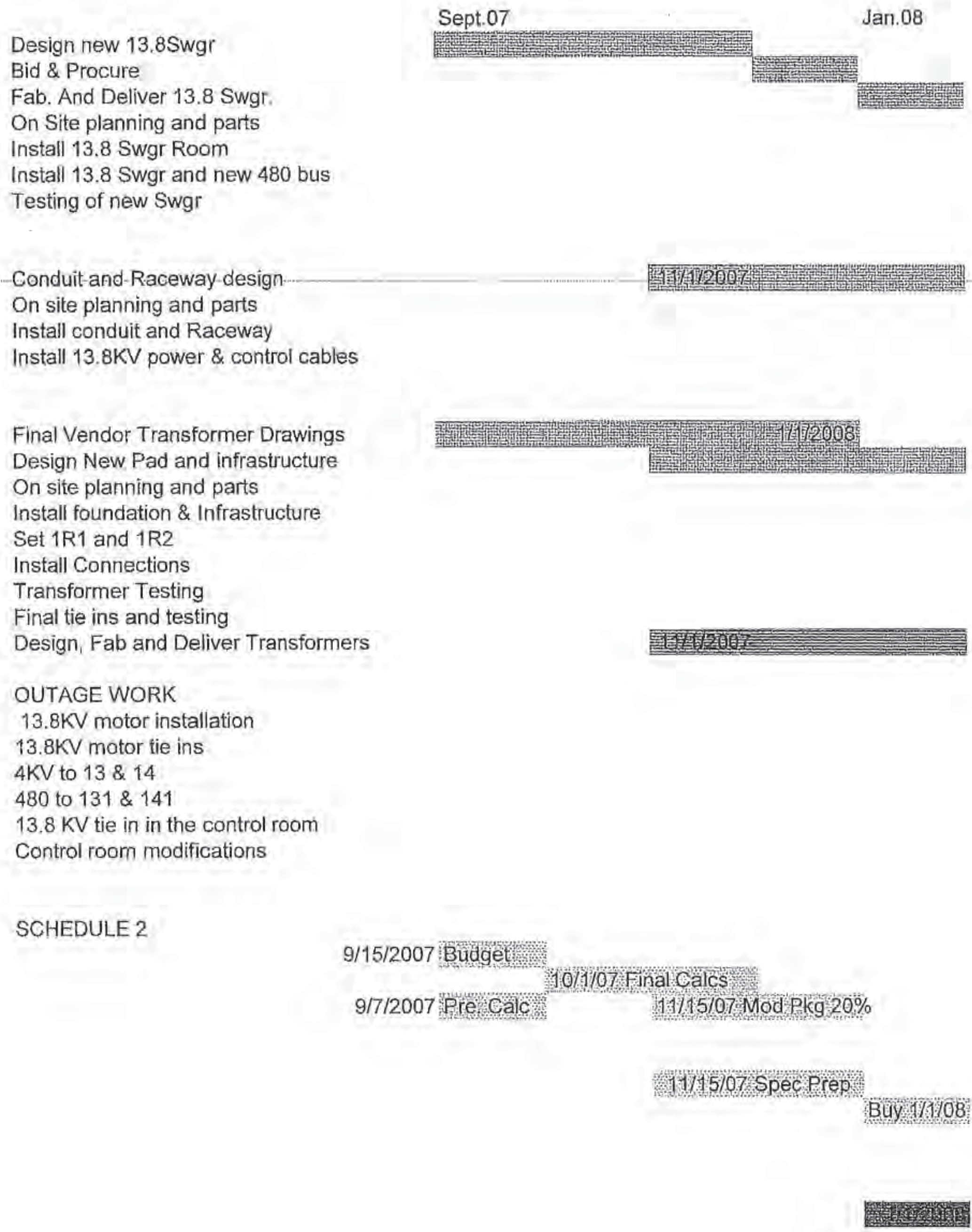
- Off loads existing system by removing reactor feed pumps from existing 4160V system
- Maximum electrical system capacity for future growth
- No need to upgrade 4160V buses from 250MVA to 350MVA
- New feed from 13.8kV can be used for new 480V transformer feeds.
- Most of the electrical installation can be installed prior to the 2009 outage.
- The starting of the reactor feed water pump motor no longer is a concern for offsite voltage.
- Provides space for four breakers where existing buses 11 and 12 presently are located.
- Adds voltage control for existing 1R sources. This improves the voltage range for the 115kV system required for Monticello plant.
- Resolves life cycle concerns for transformer 1R

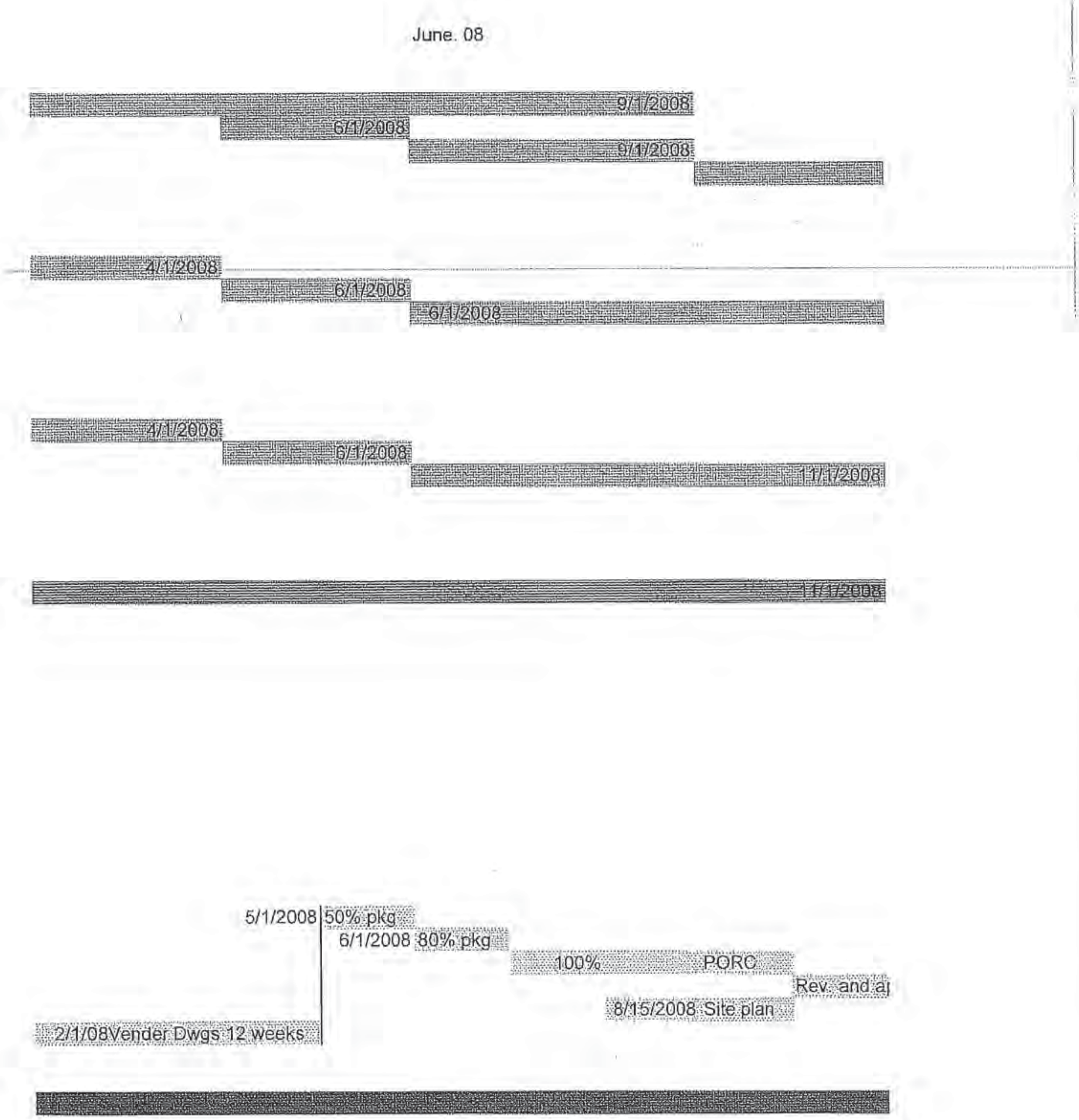
Cons:

- Reactor recirculation pump MG set motors need to be replaced as 13.2kV motors. (or move condensate pump motors to new 13.2kV bus and move reactor recirculation MG motors to buses 13 and 14)
- Need new 15kV conduit and cable runs to feedwater pump motors, recirculation MG set motors and condensate motors.
- Can we make a new 13.2kV motor fit in feed pump room since it is longer than existing motors?
- Need to find a location to install the new 13.8kV and 480V buses and the 13.8kV/480V transformer. (Possibly locate in turbine building extension.
- New equipment requiring maintenance and operations department training.
- New foundation, oil containment, fire protection(sprinklers/deluge) and fire walls for new 1R transformers
- Does not resolve aging 4160V switchgear
- Main control room and simulator for control of new 13.8kV buses and new 480V buses.
- May need to keep RR M-G Set in service for an additional cycle and old buses 11 and 12.
- May need to keep transformer 2R in service for one additional cycle.

Docket No. E002/CI-13-754
DOC Information Request No. 83
Attachment C - Page 10 of 12

Northern States Power Company




June. 08
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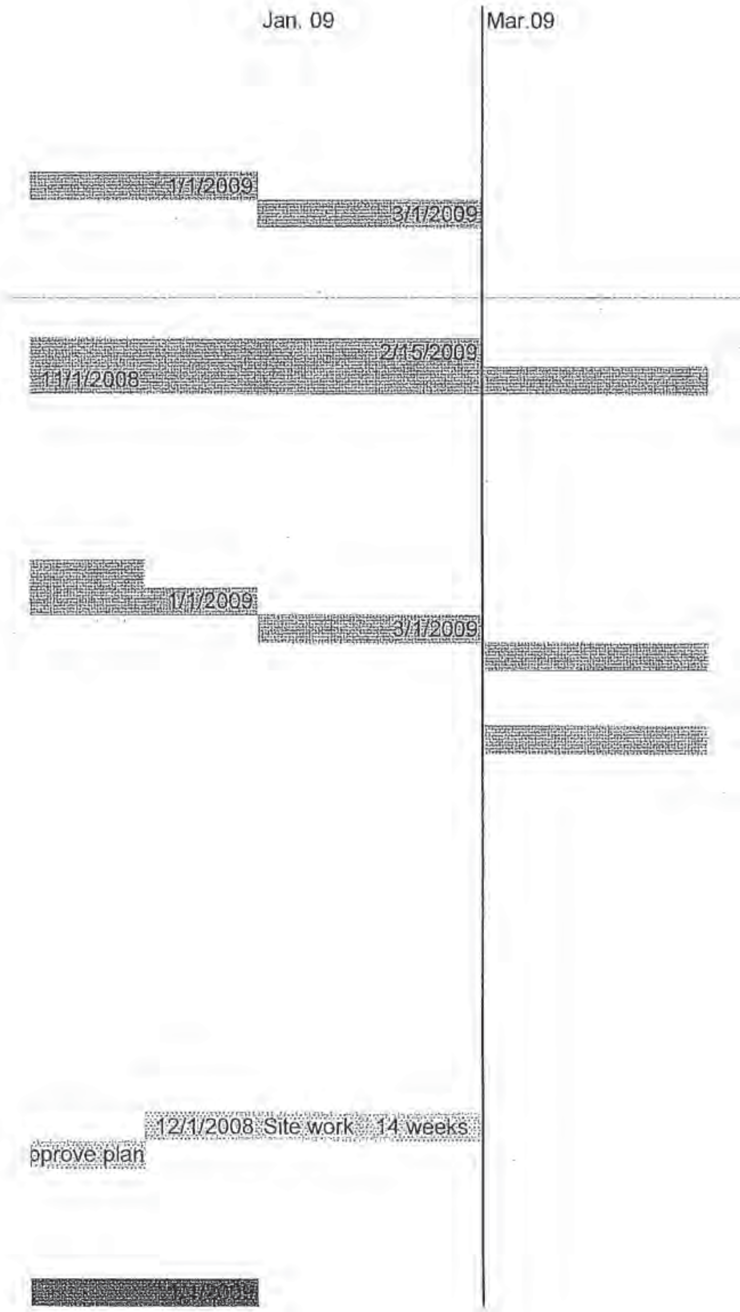
PORC
Rev. and a
8/15/2008 Site plan
2/1/08Vender Dwgs 12 weeks


Jan. 09
Mar.09
1/1/2009
3/1/2009
2/15/2009
11/1/2008
1/1/2009
3/1/2009
12/1/2008 Site work 14 weeks
pprove plan

Monticello Executive Steering Committee

November 14, 2007

Agenda

- Steam Dryer Status (discussion)
- Electrical Options
  - Decision requested
- PRNM and EPU submittal status

Project Principles

- Maintain or improve safety and risk profile
- Improve or enhance equipment reliability
- Follow existing regulatory processes
- Use industry operating experience
- Coordinate with License Renewal and Life Cycle Management projects
- Minimize the impact on day-to-day operation
- Extract value from standardization, economies of scale, with minimal duplication

Steam Dryer Status

REV. 4 to MODEL

- CDI work indicated modifications not needed for SD due to structural issues
- GE Owners Group items
- Status on qualification of bidders for new Steam Dryer for MCO issue → 1st QTR 2008
  - ☐ Capability to instrument SD
  - ☐ Industry review of SD SPEC.

(W) 11/16/07 - am

HOPE CREEK
- Another set of RAI's
- Confident that their SD Submittal is OKAY
- GE → Contradicts HOPE Creek's conclusion
- Quantitative justification required

TVA
- Negotiating with NRC on Units 2 & 3 : Unit 1 instrumented SD

Northern States Power Company

FW and CD Electrical Issue

- Larger RFP motors (8,000 Hp vs. current 6,000 HP) reduces 4KV bus voltage below allowable standards during pump start.
  - This will require upgraded bracing of bus work and higher capacity breakers to handle fault currents
    - * Breakers are an LCM mod, bracing not budgeted

Electrical Summit

- Held on site Sept 2007
  - Attendees from site, GE, Shaw
- Goal was to come to resolution on electrical design issues concerning FW, CD systems
- 2 main solutions evaluated
  - 4.160kv option
  - 13.8 kv option

Possible Solutions

	Current Option 4,160kv	New 13.8KV Option
Scope Unique design	Replace existing RFPs, piping and valves Replace condensate pump impeller and add a new 2500 HP motor Relief valve for overpressure protection 1R Xformer and 480V dist panel repl. And 4KV switchgear and breaker upgrades	Replace existing RFPs, piping and valves Replace condensate pump impeller and add a new 2500 HP motor Relief valve for overpressure protection 4.Kv only Replace 1R & 2R Xformers and install new 13.8KV bus for <u>RFP, Condensate pumps</u> and <u>Recirc MG set Motors</u>
Technical Issues	3 winding transformer or 2, 2 winding transformers Does not address the starting voltage dip	3 winding transformer or 2, 2 winding transformers New 13.8KV bus 1R1 2R1 1R2 2R2

DESIGN

Contingency { \$1M 4KV / \$2.5M 13.8KV }

Additional Scope Budget

Stay within \$273M

Cost Comparison

Mid Cycle 2010

2011 Electrical Generator rewind ~ 40 days

Item	4KV Option (labor & installation)	13.8KV Option (labor & installation)
1R Transformer	3,100	3,100
2R2 Transformer		1,400
New breakers for Buses 11-16	3,550	
13.8 KV Buses with HVAC		2,650
New 13.8 conduit & cable		4,700
New 4KV Cable	660	160
New Recirc MG Set Motors		1,200
480V SwGr	700	500
Eng. & Design	500	800
Contingency	1,000	2,500
Risk	1,350	
Total	10,860	17,010
LCM Credits	1R LCM 4,600	4KV Bkr Rplc. 11,600
Evaluated cost	6,260	5,410

30-40 days

20 days

Spares Refurbish 4KV \$7M

4KV Option Pros & Cons

- Pros
  - Reduced transformer cost with 2 winding transformers
  - Transformer work is non-outage
  - Potential for 9 4KV cable replacements or upgraded 3 cycle breakers
- Cons
  - Still has large switchgear outage work scope
  - Increased costs of pad and fence relocation
  - Does not resolve voltage dip on large motor start
  - Does not increase margin to allow additional loads
  - Does not meet project principles

13.8KV Option Pros & Cons

- **Pros**
  - Increases margin by removing RFP, condensate and Recirc MG set motors from 4160v buses. Meets Project principles.
  - No upgrades to the 4160v buses required
  - Most of the installation is non outage
  - Eliminates concern of starting large motors on 4160v system
  - Upgrades 2 R transformer and MG set motors
  - Will help 4kV switch gear room HVAC problems
  - Costs consistent with 4160v option, when LCM taken into account
- **Cons**
  - Change in scope
  - Extensive and complex work scope both on-line and during an outage
  - Does not directly resolve aging 4160v Switchgear and breaker concerns except to provide additional spares. Spares would require refurbishment for use.

+25%

Recomendation

- Pursue 13.8 kV option ROBUST electrical system
  - Defer installation until 2010 or 2011 (to be determined later)
  - Mods to be deferred
    - FW Pumps and piping
    - FW Reg Valves
    - Condensate Motors and impellers
    - GEZIP
  - Net MWe gain w/o these mods – 15 MWe

Resolves a current Loading issue

• Additional Design

• Drop Dead Date •

PRNM and EPU Submittal Status

• GE •
Follow Susquehanna's PRNM Submittal

- PRNM
  - Calculations (required by contract) necessary for new TS setpoints will not be completed until late December
    - Likely 6 week delay (until mid January) for PRNM submittal
- EPU
  - Schedule remains 1 month behind, corrective actions not effective in regaining schedule
    - Likely new submittal date early March 2008
    - EPU will likely not be approved for 2009 outage, but is not necessary, mid cycle implementation possible and has happened at Monticello previously.

FW Heater Replacement

Scope of Modification

The EPU project will *replace the 13, 14 and 15 FW heaters*. This replacement is an LCM item since the existing units could be justified for use under EPU conditions for a fraction of predicted cost for replacement.

E-14A is nearing end of life based on tube plugging. The 13 heaters may have an early trend of accelerating tube plugging indicative of need for action. The 15 heaters are original equipment that is currently operating well beyond original size ratings; EPU will push these to higher loads. Based on these conditions an LCM item has been approved to replace these heaters. This change will be implemented by the EPU program to allow these units to be sized for EPU conditions.

In addition this work will potentially require *installation of bypass lines for the 12 drain coolers to limit drain cooler velocity*. There may also be a need to have some flow through the 11 dump valves to limit 11 drain cooler flow rates. These are contingent changes based on final vendor evaluation of drain cooler capability. This change may be contingent based on nozzle size changes for these same units that are discussed in the modification for replacement of drain and dump valves.

Work will include *rerating the design temperature of the 12 heaters and drain coolers*. The temperature upgrade required is 3°F.

The new units will include all new local instrumentation and small bore valves. The material selection of the 13 and 14 heaters will be optimized based on the specifications used to replace the 13 heaters in 1982 to minimize erosion issues. The 15 heaters can be replaced with materials identical to original construction since this has stood up well. Heaters will have a design margin of 10% to address ability to plug tubes as needed.

Use of larger sized heat exchangers on the turbine floor may impact floor loading limits. Floor loading limits will be reviewed and *structural steel supports modified as needed* to support adding required loads to the floor.

Background for Existing Units

The 11 and 12 feedwater heaters were replaced by Modification 88Z013, Replacement of Feedwater Heaters 11A, 11B, 12A & 12B. These units are operating acceptably.

The 13 heaters were replaced in 1984 due to severe erosion/corrosion of the original carbon steel materials in these units. Extensive repairs to the 13 heaters were performed in 1980 to allow additional interim operation for these units. The majority of the damage was due to operation with carbon steel components in an oxygenating environment in a temperature range that maximized erosion. Failure was accelerated by operating these units with too low of a water level for the first 10 years of plant operation. The replacement heaters have operated reasonably well with early signs showing up of a potential trend in tube wear. This could be occurring due to increased clearances in tube supports.

The 14 and 15 heaters were provided with original construction. The 15 heaters have operated with few issues over the years. The 14 heaters had localized erosion of carbon steel materials in the vicinity of the extraction steam inlet lines that led to replacement of 8' by 8' sections of shell material in this area with "wall papering" of the internal diameter with stainless steel to avoid future problems. This occurred under Modification 00Q020, Repair E-14A and E-14B FW Heaters, in 2000. The 14A heater also had an impact plate failure that caused extensive tube plugging that was repaired.

Impact plate reinforcement has also occurred in the drain coolers.

FW Heater Replacement

Typically end of life of feedwater heaters and drain coolers in the industry is driven by the number of tubes plugged in these units.

Component	Tube Count	Plugged Tubes	Percent Plugged	Age, Yrs	TTD
E-DC-11A	1630 Straight Tubes	7 plugged	0.4%	36	
E-DC-11B	1630 Straight Tubes	1 plugged	0.1%	36	
E-DC-12A	833 Straight Tubes	29 plugged	3.5%	36	
E-DC-12B	833 Straight Tubes	2 plugged	0.2%	36	
E-11A	1157 Straight tubes	1 plugged	0.1%	18	6
E-11B	1157 Straight tubes	1 plugged	0.1%	18	5
E-12A	888 Straight tubes	0 plugged	0%	18	12
E-12B	888 Straight tubes	1 plugged	0.1%	18	9
E-13A	1245 U-Tube	34 plugged	2.7%	22	7
E-13B	1245 U-Tube	14 plugged	1.1%	22	8
E-14A	1250 U-Tube	102 plugged	8.2%	36	9
E-14B	1250 U-Tube	24 plugged	1.9%	36	6
E-15A	1290 U-Tube	22 plugged	1.7%	36	14
E-15B	1290 U-Tube	54 plugged	4.2%	36	12

Based on this data, only the E-14A heater is nearing end of life. Discussions with the eddy current coordinator suggest that the 13 heaters may be starting to see the beginning of a trend of tube wear requiring accelerated plugging of tubes. Other units are relatively stabile at this time.

Feedwater heater terminal temperature difference, TTD, is an indicator of whether the heat exchanger is operating within its design rating. The original feedwater heaters were designed to operate with a 5°F TTD. Since MNGP has always operated beyond the original heater design ratings, even at the original power level of 1670 MWt, this limit has never been met for most of the heaters. This can be addressed by installing larger capacity units. Physical size restrictions prevent using larger units with the 11, 12 and 13 heaters. Higher TTDs will lower respective feedwater temperatures and will impact cycle efficiency to some extent. Cycle efficiency gains would not be expected to provide sole justification for heater replacement.

Based on existing tube plugging trends and heat capacity of the existing units, the typical EPU plant would only replace E-14A. The 13 heaters should be considered for replacement if an accelerating trend of tube plugging is apparent.

Feedwater Heaters and Drain Coolers Discussion of EPU Impact

A) Tube Side Pressures

The re-rated tube side design pressures for the LP heaters and drain coolers are 450 psig (TEI supplied equipment, Ref. 1) and 450 psig (Yuba Heaters, Ref. 2). Condensate pump solutions (i.e., shutoff head) must remain within this constraint when applying Code rules for overpressure protection. *Operating pressures for EPU would be well within this limit.*

Tube side design pressures for the 14 and 15 heaters are 1850 psig. Condensate and RFP solutions (i.e., combined shutoff head) must remain within this constraint when applying Code rules for overpressure protection. *Operating pressures for EPU would be well below this limit.*

B) Tube Side Design Temperatures

Leaving tube side temperatures from the heat balance evaluations are compared to design conditions as follows:

FW Heater Replacement

Feedwater Heater Tube Side Operating Temperatures (°F)

Parameter	Design	Current	EPU
5th Point	390	384	394
4th Point	345	338	347
3rd Point	350	304	312
2nd Point	240	237	243
2nd Point DC	229	190	195
1st Point	231	172	176
1st Point DC	145	117	118

Operating temperatures would exceed current design values by a small amount for the 2nd, 4th, and 5th point (underlined values). The thermal expansion stress from a 70 F ambient is <2% above design values. Further, material strength for ASTM materials used in feedwater heaters is not strongly dependent on temperatures in this range. Therefore, *it is considered to be highly probable that the heaters can be re-rated to a design pressure*).

C) Shell Side Design Pressure

Shell side operating pressures from the heat balances are compared to design values below:

Feedwater Shell Side Operating Pressures (psig)

Parameter	Design	Current	EPU
5th Point	250	196	227
4th Point	150	92.7	106
3rd Point	105	56.4	65.8
2nd Point	50	10.4	13.9
2nd Point DC	50	<25	<25
1st Point	50	Vacuum	Vacuum
1st Point DC	50	<10	<10

As illustrated in the table, *all heaters and drain coolers are expected to have shell side operating pressures within design values.*

D) Shell Side Design Temperature

Shell side operating temperatures from the heat balances are compared to design values below:

Feedwater Heater Shell Side Operating Temperatures (°F)

Parameter	Design	Current	EPU
5th Point	400	389	401
4th Point	350	343	353
3rd Point	350	309	318
2nd Point	250	242	249
2nd Point DC	245	241	248
1st Point	185	177	182
1st Point DC	185	175	180

Projected shell side operating temperatures exceed design values by a small amount, <2% on a thermal expansion from ambient measure. Further, material strength for ASTM materials used in feedwater heaters is not strongly dependent on temperatures in this range. Therefore, it is considered to be highly probable that the *heaters can be re-rated to slightly higher design temperatures for the shell side* without compromising design pressure.

FW Heater Replacement

Based on feedwater heater design temperatures and pressures, the typical EPU plant would rerate the existing units to the slightly higher temperatures expected. The maximum rerate is a temperature increase of 4°F.

Subcooling Zone Flow Rates

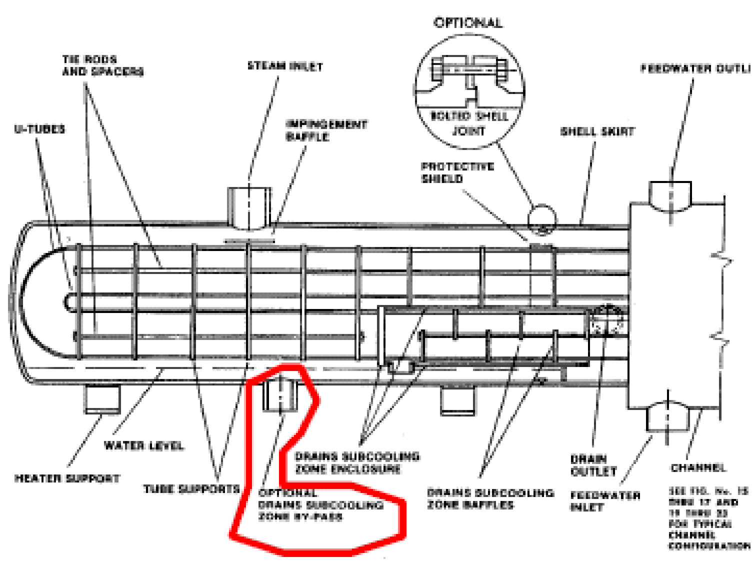
Feedwater heater drain cooler flows would increase with EPU and possibly exceed vendor allowable values. The differences are more easily recognized when drain cooler flows are shown as a percentage of the original operation.

Feedwater Heater Drain Outlet Flows (% of Original)

Parameter	EPU	NEPU
5th Point	109%	131%
4th Point	108%	124%
3rd Point	108%	125%
2nd Point DC	108%	126%
1st Point DC	108%	127%

The current (EPU) drain cooler flow rates are ~109% of the original design condition. Projected drain cooler flow rates for the NEPU (without reheat option) vary from 115% to 120% of the current condition and 124% to 131% of the original design. The increased drain cooler flows would cause an increase in the drain cooler pressure drop and possibly cause flow induced vibration issues in the drain coolers (subject to vendor verification).

The diagram below is from HEI Standards [Ref. 1 Fig. No 26], and illustrates the typical 2-zone feedwater heater with an optional drain cooler bypass nozzle. This nozzle is potentially required for Heaters 13, 14, and 15, depending on vendor evaluations for DC zone vibration for EPU flows.

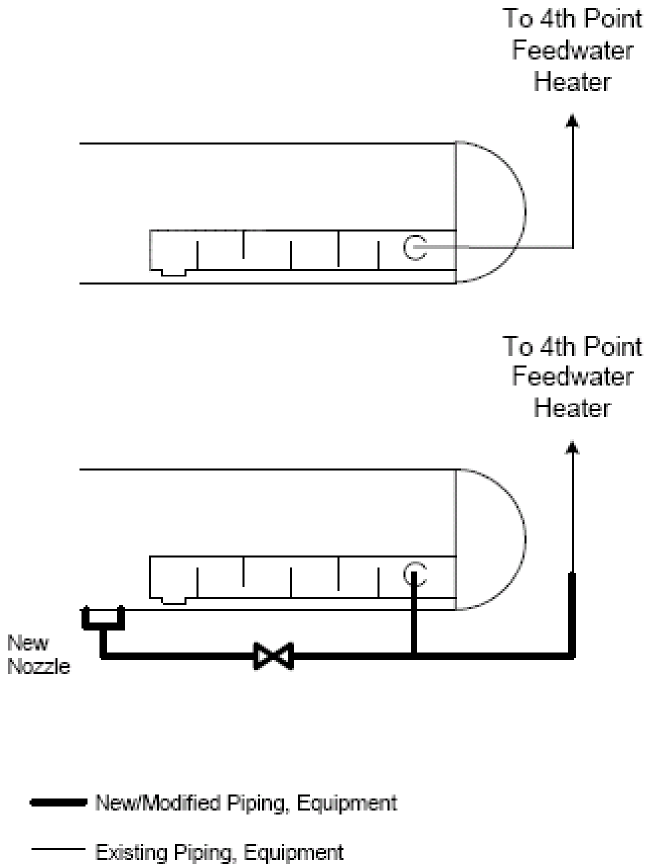


TYPICAL 2-ZONE FEEDWATER HEATER
(Condensing and Subcooling Zones)

Fig. No. 26

FW Heater Replacement

Heater 15A/B Schematic for Drain Cooler Bypass



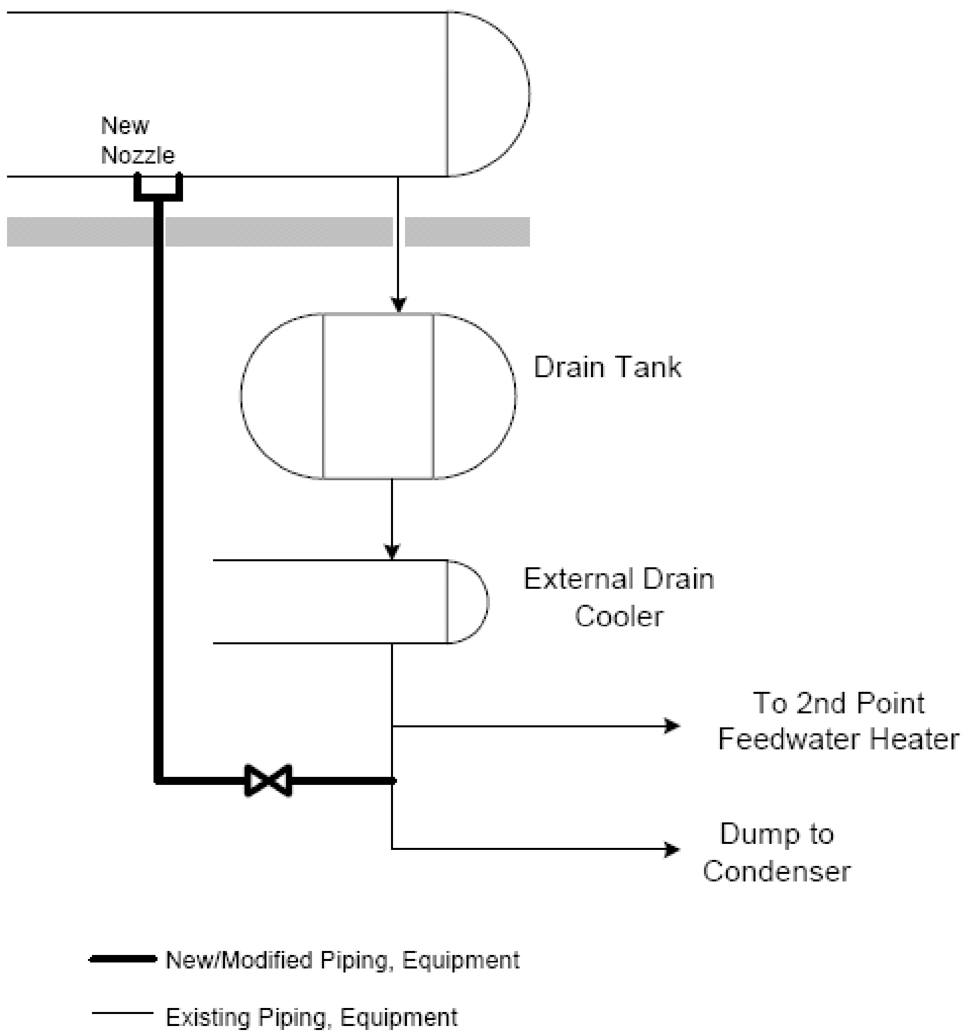
Heater 15A/B Schematic for DC Bypass

Drain cooler bypasses for the 14 and 15 heaters would be similar to what is shown above for the 15 heaters. *No bypasses would be required for 13, 14 or 15 heaters if new units are installed that are sized appropriately for the correct flow rates.*

FW Heater Replacement

External Drain Cooler # 2 Bypass (Dump to Condenser)

The 2nd point external drain cooler bypass requires the addition of a drain nozzle to the 2nd point FWH, new piping, and the bypass valve to connect the bypass line to the external drain cooler condenser dump line as shown on the diagram below. The new line would bypass both the drain tank and the external drain cooler. *The drain cooler will be evaluated and if required this bypass line will be installed. Use of this line may eliminate the need to increase the size of the nozzle due to heater evacuation concerns.*



External Drain Cooler # 1 Bypass (Dump to Condenser)

The 1st point external drain cooler bypass requires no physical changes to the feedwater heater or piping. This option utilizes an existing condenser dump line and the dump control valve. The only changes required would be to *change the normal operation which would permit continuous partial dump of the 1st point feedwater heater drains*.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CI-13-754 (Commission Investigation into the Monticello LCM/EPU Project)

Date Request Received: July 24, 2014

Date of Response: August 5, 2014

Person Requesting Information: Timothy J. O'Connor

Response submitted by: William R. Jacobs, Jr., Ph.D.

Request No.	
20	Re: Direct Testimony and Attachments of William R. Jacobs, Jr., Ph.D. Reference Jacobs p. 13, lines 3-4. You state: "I learned during my site visit that replacement of the condensate demineralizers would not have been necessary absent the EPU requirements." Please state from whom you learned this information and what was the specific question asked that led to this conclusion. Also, would you please submit the question(s) in the form of written discovery on the Company so that a response to your question can be submitted in writing? DOC Response: I learned this during a discussion with Mr. Bjorseth during the plant tour. I do not recall the specific question. It was in the context of a general discussion of the condensate demineralizer replacement. As I do not recall the specific question, I cannot submit it in discovery to the Company.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CI-13-754 (Commission Investigation into the Monticello LCM/EPU Project

Date Request Received: 7/30/14

Requested By: Xcel Energy

Date of Response: 8/11/14

Person Requesting Information: Timothy J. O'Connor

Response submitted by: William R. Jacobs, Jr., Ph.D.
Title: Executive Consultant
Division/Unit: GDS and Associates, Inc.
Telephone: 770-425-8100, Ext. 1135

Request No.	
26	**Question:** RE: Direct Testimony and Attachments of William R. Jacobs, Jr., Ph.D. Executive Consultant with GDS Associates, Inc. Docket No. E002/CI-13-754 – July 2, 2014 Reference page 13, lines 17-19 – You state: "The nuclear industry has shown that it is able to perform well when replacing steam generators in major construction project, but only when the update is a 'like-for-like' project." Please explain the basis for this statement. **Response:** The basis for this statement is my knowledge of the nuclear industry performance replacing steam generators at pressurized water reactors. After the initial learning curve associated with early steam generator replacement projects, most replacements were conducted within schedule and budget. Replacement steam generators are generally designed to be physically very close if not identical in size and weight to the original generators to minimize complications with fit up[1] and support within the reactor coolant system. With some exceptions such as the steam generators at the San Onofre nuclear plant, the replacement steam generators have performed well.

[1] In general, "fit-up" means achieving alignment within very tight tolerances to allow welding of two components together. During a steam generator replacement this usually refers to alignment of reactor coolant system piping to allow reconnecting the steam generator with the reactor coolant system.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request Response

Docket Number: E002/CI-13-754 (Commission Investigation into the Monticello LCM/EPU Project)

Date Request Received: July 24, 2014

Date of Response: August 5, 2014

Person Requesting Information: Timothy J. O'Connor

Response submitted by: William R. Jacobs, Jr., Ph.D.

Request No.	
17	Re: Direct Testimony and Attachments of William R. Jacobs, Jr., Ph.D. Reference Jacobs, p. 12, lines 15-16. You state: "Moreover, the timing of such life extension projects most likely would have been significantly later, if at all." Please identify the equipment you believe would not have needed to be replaced through 2030, and provide a detailed explanation supporting your conclusion for each piece of equipment identified in response to this question. DOC Response: The statement referenced is a general statement based on my experience. I have not identified specific equipment that would not be needed to be replaced.