BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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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	MPUC Docket No. E002/CI-13-754 OAH Docket No. 48-2500-31139

DIRECT TESTIMONY AND ATTACHMENTS OF MARK W. CRISP, P.E.

ON BEHALF OF

THE DIVISON OF ENERGY RESOURCES OF THE MINNESOTA DEPARTMENT OF COMMERCE

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I. INTRODUCTION AND PURPOSE

Q. Please state your name, title and business address.

A. My name is Mark W. Crisp. I am the Managing Consultant of Global Energy & Water Consulting, LLC. My business address is 4539 Woodvalley Drive, Suite 100, Acworth, Georgia (Suburban Atlanta) 30101.

Q. Please provide your educational background and experience.

A. I graduated from the Georgia Institute of Technology (Ga. Tech) with a degree in Civil Engineering. In addition to my studies in Civil Engineering, I also completed post graduate studies in Finance and Accounting. Following completion of my formal education, I was employed for seventeen (17) years by Arkansas Power & Light (Middle South Utilities now Entergy – Arkansas) and Georgia Power Company/Southern Company. During this time, I completed assignments in the planning, siting, design, construction, and operations of nuclear, coal and hydroelectric generating plants. In addition to my utility operating experience, I was also responsible for technical due diligence on Southern Company's International Acquisition Team. In this capacity I was responsible for evaluating all operating, environmental, staffing and operational aspects of power generating facilities, worldwide, that were the focus of Southern Company's acquisition strategy.

Following my employment in the utility industry, I became a consultant providing services to electric, water, wastewater and natural gas utilities and regulatory bodies throughout the continental U.S., Hawaii, Alaska and internationally. I continue to provide these services as Managing Consultant at Global energy & Water Consulting, LLC. A list of major electric generating facilities I have been involved with are set forth in DOC Ex. ___ MWC-1 (Crisp Direct). I am a licensed professional engineer in Georgia, Florida and South Carolina.

My direct nuclear cost, schedule and construction experience has evolved from my work at Arkansas Nuclear One 1 (ANO-1) in the early 1980's while working for Arkansas Power & light Company, then Middle South Utilities, now Entergy – Arkansas on outage projects including the pipe hanger assembly review following the Three Mile Island incident. I also provided construction support on Vogtle 1 & 2 as an employee of Georgia Power Company and Southern Company Services, Inc. My consulting also includes engagements as a consultant for El Paso Electric, a minority owner of Palo Verde Nuclear Plant, reviewing the outage costs associated with the steam generator replacement project and the rate impact to the minority owners. I am also working with the Mississippi Public Service Commission Staff on pre-construction and licensing costs filed by Entergy- Mississippi for prudence review on Grand Gulf 3, a new project proposed in Mississippi now on hold.

Q. Have you previously testified before the Minnesota Public Service Commission (Commission)?

A. No. However, I have testified before the Arizona, Georgia, South Carolina, Maryland, Mississippi and Utah Commissions. In addition, I have testified before the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), various committees of the United States Congress, and several Federal Courts in the capacity of an expert witness.

Q. What is Global's assignment in this proceeding?

A. 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. Since the goal is to identify the causes and reasons for the cost overruns that have occurred since the project was first approved, it is also necessary to identify whether the level of costs that Xcel identified for various components is reasonable. Finally, since the Extended Power Uprate (EPU) project was conducted at the same time as the Life Cycle Management (LCM) project, it is necessary to identify which cost increases are due to 1) solely the EPU, 2) solely the LCM and 3) both projects.

Q. What is the purposes of your testimony in this proceeding?

A. The purpose of my testimony is to provide a technical review of Xcel's Project Management decisions and project management execution and how they impacted costs throughout the project timeline from the point the Application for a CN was made to the Commission throughout the execution of the LCM and EPU projects.

II. BRIEF HISTORY OF MONTICELLO PLANT UPRATE PROJECT

Q. Please describe Xcel's application for Certificate of Need and its implications.

A. Xcel submitted to the Commission its application for a CN for an extended power uprate to increase the generating capacity of the Monticello Plant on February 14,

2008. The Commission granted the *Order for Certificate of Need and Accepting the Environmental Assessment* on January 8, 2009 (Docket No. E-002/CN-08-185). In short, Xcel's application proposed to increase the generating capacity of the Monticello Nuclear Plant from 600 MW to an uprated capacity of 671 MW.

Q. Was this the first uprate project or Monticello Plant?

A. No. Monticello went through a similar uprate project in the late 1990's beginning with its request submitted to the NRC dated July 26, 1996. On September 16, 1998, the NRC granted Xcel (then Northern States Power Company) an Amendment to its Facility Operating License (No 102) allowing Xcel to increase the maximum reactor core thermal power level by 105 MWt, from 1670 MWt to 1775 MWt (6.3 percent increase). Monticello was able to increase its electric output from a nominal rating of 550 MWe to a nominal value of 585 MWe.[1]

Q. How was Xcel able to accomplish its first uprate during the late 1990's?

A. The original design of Monticello, as with any nuclear, coal or natural gas plant, included additional operating margins with each component. It is normal to include this additional margin in order to absorb some efficiency losses as equipment ages over time. During the planning and design for the 1998 uprate project Xcel used these margins in the existing equipment to uprate the electric output while making all necessary modifications to meet NRC requirements for operational safety at the new power output level.

[1] One MW represents one million watts of energy, but does not specify the type of energy. For greater clarity, one MWe represents one million watts of electrical energy; by contrast, one MWt represents one million watts of thermal energy. In MW terms, the uprate approved in 1998 increased the capacity from 564 MW to 600 MW.

Xcel and General Electric (GE), the original plant designer, had to evaluate exactly what the differential between the existing plant systems and the proposed higher power output would require from those same plant systems while also making certain that NRC requirements were met. This analysis and the subsequent uprate produced a new "design basis" for the plant. The Company, in its application for certificate of need discussed the original uprate project in 1998. The Company articulated that:

> This first power uprate at Monticello was completed by making use of available excess equipment, system and component capabilities at the site. The site was able to increase generation by 35 MWe to a nominal net electrical output to the grid of 585 MWe with very few changes to installed plant equipment.

Cite: February 14, 2008 Petition to the Minnesota Public Utilities Commission for CN, Docket No. E002/CN-08-185 at 3-14.

III. ANALYSIS OF XCEL'S PROJECT MANAGEMENT

Q. From a project management and project execution perspective, why is it important to return to the original uprate project for discussion?

A. 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. This as-built condition should have established the baseline, or original starting point, for the conceptual design, implementation schedule, and cost estimate for this power uprate project. The "as-built" condition would have or should have also identified any excess component capability or expansion capability of the existing plant components. The completion of the original uprate program in 1998 was able to take advantage of all available operating margins of electrical and mechanical components of the plant. As a result, the latest life cycle management and extended power uprate programs had to start from essentially a fresh start to increase capacity further.

Q. Why was the fresh start for the 2nd EPU important for the project management?

A. As with every major project and most minor projects the overall execution of the project is directly attributed to thorough and exhaustive project management. Success is defined by the schedule, cost, and operational benefits the project is able to accrue to the plant and to the ratepayers. Each attribute of overall project management, including proper staffing, scope definition, scheduling, budgeting, design, procurement, and construction is linked together to form a synergistic approach to the overall execution of the project. A project cannot expect to be completely successful if any one or more of the attributes fails to meet its goal.

Each of these attributes must be addressed as thoroughly as possible in the initial project definition and the expectations defined for the schedule, scope, design, construction, start-up, operation, and final cost. The project management for the Monticello project suffered from failure of several of these activities to be adequately defined and for responsibility to be assigned to fully able and skilled personnel at each step in the process.

Q. Please explain in more detail your assessment of the project management

A. The project management function in any multidiscipline project requires extensive and accurate pre-project definition. In the case of Monticello, a fully functioning and operating nuclear plant, it is even more critical to establish the scope in great detail.

Failure to establish the scope at the outset all but guarantees schedule delays and cost overruns.

Q. What kinds of issues need to be fully considered at the beginning of such a project?

A. Establishing the scope for the LCM/EPU project requires considerable coordination among all of the involved departments of Xcel, internal management of Xcel, the original designer of Monticello, the current responsible designer, in this case GE, and all sub-designers supporting the original design and the scope of the LCM/EPU. These entities need to accomplish the following tasks at the beginning of the project.

In an established and functioning plant the first step in developing the scope of any project is to define the final outcome; that is, what is the project to accomplish, how will the project be accomplished, and what is the scheduled completion or operational date the project is to be completed.

Secondly, before any design is initiated, a fully integrated team representing operations and designers must be assembled for the purpose of determining the existing condition of plant equipment, whether the existing equipment has adequate capacity to be used in the future plans or whether the existing equipment does not have the remaining life or capacity to work within the new scheme.

At this point in the scoping process the goals of the project must be specifically identified in order for the design team to begin the process of establishing the requirements for new and replacement equipment.

In a parallel effort, the design team along with the plant operational team must be physically evaluating the logistics required to dismantle any retired existing equipment and remove those components from their specific installation sites within the plant while determining the physical size and installation requirements of the new equipment. Failing to follow these steps in the planning and design process almost guarantees schedule delays and cost overruns during the actual process of constructing the project.

Q. Did the issue of project management failures as you have described above occur during the LCM/EPU project?

A. Yes, as acknowledged by the Company, initial scope definition and project planning appeared to contribute significantly to the cost overruns of the Monticello LCM/EPU project. The licensing process with the NRC was another area testified to by the Company that caused cost overruns. However, as discussed in more detail by Dr. William Jacobs and further explained later in this testimony, NRC delays did not cause delays in the LCM/EPU project.

Q. What did the Company indicate about the inadequacy of their initial cost estimates?

A. Company Witness Mr. O'Connor expressed his understanding of the cost overruns in his pre-filed testimony (Xcel Ex. ___ at 30 – 33, O'Connor Direct), identifying several "overlapping" difficulties during the original scoping process that contributed to the cost overruns. Mr. O'Connor testified that the "preliminary nature of our initial cost estimates failed to capture the true costs necessary to implement the overall design." However, he further testified that "future requirements due to evolving regulatory environment" was a major cause of the cost overruns. Furthermore he specifically identified (i) Program design and scope changes; (ii) licensing delays; and

(iii) the complexity of the modification installation as the "major cost drivers." (Xcel Ex. ___ at 31, lines 10-15, O'Connor Direct)

Q. In general, how do you respond to these assertions?

A. While projects can experience unexpected circumstances, it was clear that Xcel did not adequately follow the steps I outlined above regarding basic project planning and management. Good project management works to avoid changes in program design and scope by careful examination of the project as I describe above. Further, good project management considers the complexity of modification installation early in the process. As discussed further below, these factors had a significant effect on the cost overruns; by contrast, our review does not support the assertion that licensing delays were in fact an issue with the delay.

Q. Will you please discuss each of the three areas Mr. O'Connor attributes to the cost overruns?

A. Yes. As noted above and as discussed below, the three areas are:

A. Program design and scope changes,

B. Licensing delays, and

C. Complexity of the modification installation.

A. PROGRAM DESIGN AND SCOPE CHANGES

Q. What did Mr. O'Connor say about changes in program design and scope?

A. Mr. O'Connor stated the following:

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

Xcel Ex. ___ at 31-32 (O'Connor Direct).

He also listed the four design changes as follows, noting that these costs accounted for $406 million, or over 60 percent of the $665 million that Xcel indicates is the total cost of the project:

> (i) replacement of the feedwater heaters and associated equipment; (ii) replacement of the reactor feed pumps and motors; (iii) replacement of the entire condensate demineralizer system; and (iv) upgrade of the 4 kV electric distribution system to supplement the on-site power capabilities of the plant.

Xcel Ex. ___ at 32 (O'Connor Direct).

Q. How do you respond?

A. Given the focus on my testimony on the reasonableness of Xcel's management of the project, I note that the program design and scope changes would have been minimized with proper initial scoping of the project. That is the function of a well thought-out scoping process. It may not have corrected all of the issues with scoping but it certainly would have minimized the issues.

For example, Xcel should have anticipated the upgrade to the distribution system at the plant early on in designing the system, rather than the ad-hoc approach Xcel used. Xcel also should have known the size specifications of the new equipment early in the process. Not having that basic information in the initial estimates indicates that Xcel wasn't thinking through the process adequately to ensure that the design and scope were reasonably worked out at that time.

B. LICENSING DELAYS

Q. What did Mr. O'Connor state about licensing delays?

A. Mr. O'Connor attributed licensing delays as one the major cost drivers. Specifically, he stated that "we expended substantially more dollars than we anticipated and more time than any prior applicant to meet the increasingly rigorous NRC standards and to provide new information in response to the NRC concerns." Xcel Ex. ___ at 34 (O'Connor Direct). While his testimony indicated that the increase in licensing costs went from $28.6 million to $60 million (increase of $31.4 million), he also stated that "most importantly, the extended and unexpected licensing effort delayed our ability to operate at uprate levels for the full duration of the extended license." Xcel Ex. ___ at 34-35 (O'Connor Direct).

Q. How do you respond?

A. As is evidenced by the NRC administrative record for the LCM license extension and the EPU increase there were in reality minimal licensing delays attributable to the NRC. The license renewal (LCM extension) process actually was completed in a very expeditious manner. The application date to the NRC was March 24, 2005 and the final decision and order was granted on November 8, 2006. The Extended Power Uprate process was more lengthy but as discussed further below, not necessarily due to NRC delays or added NRC requirements.

The EPU process was initiated November 5, 2008 with final notice provided by the NRC on December 9, 2013, a 5-year process. The 5-year process included a lengthy period amending the previous Facility Operating License and the revision to Technical Specifications that included approximately sixty-three (63) official correspondences between Xcel and the NRC. This is the time period when the Fukushima incident occurred. I discuss below how this longer time period was appropriate for safety reasons.

Q. What do you say about Mr. O'Connor's statement that the delay meant that Xcel could not use the uprate?

A. First, I note that I am not discussing the issue regarding whether the uprate will be in place in 2014; my understanding is that this issue will be developed in Xcel's current rate case (Docket No. E002/GR-13-868). Second, I note that Xcel's statement is misleading in that it appears at face value to place considerable if not all the blame on the NRC licensing process. NRC granted Xcel the License Renewal, which did not include an EPU request, in November of 2006. The EPU application did not occur until November of 2008. Had the EPU application only taken 2 years for approval, as did the initial Xcel License Renewal, given Xcel's construction period to install the EPU, the operation of the plant at the 1671 MWe level could not have commenced before 2013. Therefore, 5 years of the new extended license operating time frame would still be lost. So it is misleading to make the assertion that the licensing effort delayed the plant's ability to operate at the uprate levels for any period within the new license timeframe.

Q. Do you not see any issue regarding licensing that may have affected the costs of the project?

A. Yes. The Company's strategy leading from the License Renewal into the EPU application is not only confusing but may have had some repercussions with regards to schedules and timely issuance of the EPU approval. The NRC approved the License Renewal in a timely manner on November 8, 2006. However, on March 31, 2008, the Company applied for a license amendment for an Extended Power Uprate at Monticello, in which the Company made a statement that contradicted the statements the Company made in the request for the license extension of the plant.

Specifically, in the Application for License Renewal in 2005 the Company presented to the NRC, the Company stated:

> Nuclear Management Company ("NMC" now Xcel) does not propose to construct or alter any production or utilization facility in connection with this renewal application. The current licensing basis ("CLB") will be continued and maintained throughout the period of extended operation.

DOC Ex. ___ at MWC-2 (Crisp Direct, Docket 50-263, License No.: DPR-22, Page1-11, Section 1.3.5)

However, contrary to this commitment to the NRC, the Company initiated studies and activities for the EPU as early as 2004 and it was 2 years from the date the extended license was approved that the Company filed with the NRC a request for a power uprate amendment.

On June 25, 2008, at the suggestion of the NRC, the Company withdrew its Extended Power Uprate amendment request. The Company returned to the NRC on November 5, 2008, and renewed its Extended Power Uprate amendment request. The confusion, contradictory information to the NRC and start-stop process suggest management indecisiveness and strategic planning that, at best, was not adequately thought out. Further, these factors presented timing and schedule interruptions that caused cost increases.

Q. Do you have other observations about the licensing delays?

A. Yes. I conclude that the licensing delays were not wholly the responsibility of the NRC as Company Witness Mr. O'Connor suggests in his testimony at Page 34, Lines 2-15. Moreover, part of the longer time period for the EPU was due to the NRC's focus on safety and public health, a goal that Xcel shares. For example, the Company was required to perform extended analyses in order to meet various NRC requirements as a result of the Company's reasonable decision to use the NRC guidance regarding the higher water temperatures in EPU's (SECY-11-0014 CAP).[2] Xcel's Monticello EPU application was the first to use this guidance. Without getting into the technical details it is understandable that the schedule was delayed and costs impacted by the

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[2] NRC staff describe NRC guidance SECY-11-0014 CAP as follows:

> EPUs result in an increase in the temperature of the sump water (in pressurized-water reactors) and suppression pool water (in boiling-water reactors) during certain postulated accidents or abnormal events. This could affect the performance of the emergency core cooling system (ECCS) pumps taking suction from these water sources. In some cases, licensees have included containment accident pressure (CAP) in their safety analyses to demonstrate acceptable performance of the ECCS pumps. The [Advisory Committee on Reactor Safeguards] ACRS recommended changes to this practice in a letter to the Executive Director for Operations (EDO) dated March 18, 2009.

May 25, 2011 NRC memo of Eric J. Leeds to NRC Commissioners approach the Company elected to use with the SECY -11-0014 CAP guidance. Thus, if it was Xcel's intention to do so, it is not fair or supportable to suggest that the delays and costs were solely the responsibility of the NRC in its licensing process. While neither Xcel nor the NRC could have anticipated that the Fukushima incident would have occurred prior to that event, the Company's election to use the SECY -11-0014 CAP guidance, which was new, resulted in a longer than normal approval process.

Relating this issue to the Project Management issue, I conclude that Xcel's Licensing Team should have maintained extensive two-way communication with the NRC as to the vulnerability of schedules using the chosen analysis path. The Licensing Team should have been in constant contact with the NRC, particularly if a new criterion or guidance was to be used in the license analysis phase.

C. COMPLEXITY OF THE MODIFICATION INSTALLATION

Q. What does the Company indicate about the complexity of installing the plant modification?

A. The complexity of installing the plant the modification appears to be the single largest impact to schedule and cost of the Project, as identified by Mr. O'Connor's Table 6. Specifically, Mr. O'Connor stated:

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

Xcel Ex. ___ at 35 (O'Connor Direct)

That is, Mr. O'Connor blames inadequate initial cost estimates for installation as causing 40 percent of the cost overrun. The figures above indicate that Xcel exceeded its original estimated installation cost of $27.5 million by 955 percent.[3]

Q. What are you observations about Xcel's cost overruns for installation?

A. It is troubling that this area caused so much of the cost overrun since this is the area where: 1) the Company and the Company's contractors had the most control and 2) advanced planning and information should have negated this area as a cause of cost overruns. It is crucial for managers of any project to have a clear understanding of the "complexity" issue whether it is in the licensing phase, design phase, material manufacture phase, construction phase or start-up phase or any combination of these areas.

It is also 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. A design can be fully functional "on paper." However, other issues may mean that the design cannot be physically built; these issues are called controlling factors. In order to avoid such failures the Project Management Team must require considerable time for the construction sub-Team to review and sign-off on the design that it can actually be built as designed.

Further, the level of communications between the design sub-Team and the construction sub-Team is much more important in a retrofit project,

[3] Calculated as ($290 - $27.5)/$27.5*100 = 955.

such as the Monticello uprate, than in a new or "greenfield" site especially when the project involves substantial increases in power as is the case with Monticello. The design of "renewals and replacements" has controlling factors that a greenfield site generally does not contend with during the design.

Q. What were some of the controlling factors for the Monticello updrate?

A. For Monticello, controlling factors included spacing, clearances, access, physical arrangement, as well as existing capacity of certain equipment that would continue to function in the uprated environment. These controlling factors clearly had material effects on the costs of the project. Further, failure to recognize these conflicts is a direct failure of Project Management.

Q. How could Xcel have recognized these controlling factors earlier in its planning for this project?

A. This plant had been in operation for 40 years, with outages occurring roughly every two years. During these outages, plant operating personnel were required to inspect all sections of the plant. Obviously, Xcel was well aware of the physical arrangement with the plant power block itself. Xcel and GE, the original designer of Monticello, and the contractor hired by Xcel to perform initial scoping, design, and provide cost estimating services knew or should have known about the physical arrangement inside the power block. In addition, as acknowledged by Xcel, NRC regulations require the Owner, Xcel, to maintain complete documentation as to design, design modifications made throughout the life of the project, and/or any changes in the Plant's physical arrangement that may have an impact on the design basis. Generally speaking this is commonly referred to as the "as-built" condition.

Company Witness Mr. O'Connor's testimony recognized this need for careful design to some degree:

> As required by the NRC regulations and our [Xcel's] commitment to nuclear safety, we [Xcel] **regularly reevaluate the functionality and performance of the plant's systems and components**. During the evaluations performed in preparation for the Program we [Xcel] took care to identify **all** components necessary to enable operations through life extension so that we could implement those changes during the 2009 and 2011 outages. These evaluations resulted in **new modifications and component replacements** being identified as necessary to complete the LCM/EPU Program. (Emphasis added).

Xcel Ex. ___ at 31-32 (O'Connor Direct)

Further, Mr. O'Connor goes into detail about Xcel's initial evaluations and further emphasizes that Xcel identified "all" components. He also explains the impacts of Monticello's 1960's construction, in that the original design was constructed on a "very small footprint" causing this LCM/EPU design to be "limited in range of options and made aspects of installation more challenging. (Cite: O'Connor Testimony at Page 33, Lines 1-3).

Q. How did the "very small footprint? Affect the complexity and cost of the project?

A. In simple terms, when the Plant was initially constructed, there were small "rooms" that are like concrete vaults in the Plant that were built to contain the necessary equipment inside the Plant. Gaining access to those "rooms" to remove existing equipment and install new equipment is much more difficult and costly than Xcel anticipated; however Xcel should have anticipated this difficulty and cost.

For example, Xcel knew the dimensions of the containment “room” for the feedwater heater. However, Xcel’s estimated cost of installing the new, much larger feedwater heater did not take into account the significant difficulty in removing the former feedwater heater, modifying the size of the then-existing concrete “room” and installing the new, larger feedwater heater. In addition, Xcel was aware of the size of the cable tray, where all cables were located, and should have been aware of the significant difficulty that would be involved in installing the new cable equipment.

Q. How do you respond to Xcel’s arguments about the “very small footprint” being an unexpected source of complexity for the project?

A. While there is no dispute that the age of the design and the small footprint affected costs, it should not have been a critical issue causing cost overruns in the actual design of LCM/EPU nor should these controlling factors have been a surprise to Xcel or GE for construction; GE was the original designer and had access to all of this information. It is simply unclear where the breakdown occurred that ultimately lead to the cost increases and increased constructability costs; “complexity issues” should not have been the cause of such high cost overruns of installation.

Q. What do you conclude from your observations?

A. Unfortunately, in my opinion, it does not appear that the level of skilled Project Management, communications, and sufficient support for employees entrusted to carry out the project was focused on this project until the later construction time period when it became obvious to the Company that costs were spiraling far above expectations.

Q. Please provide a short chronology of events leading up to the filing in this case that you conclude had an impact on project management.

A. The project suffered from a number of "starts and stops," changes in company management, changes in design and construction team, and an overall disjointed process.

- **2006** GE is engaged as the engineering, procurement and licensing team responsible for the Monticello LCM/EPU project.
- **2007** Xcel chooses the Team of Day Zimmerman/Sargent Lundy instead of GE to complete the project.
- **2010** Poor performance on the part of Day Zimmerman/Sargent Lundy led to transfer of some project scope to Northern States Power (NSP), Xcel, and then on to other contractors.
- **2011** Xcel retains Bechtel Corporation to take over and complete the LCM/EPU project.

Each of these course corrections occurred at a time that significant cost increases were experienced; however, as discussed further below, there were additional cost increases not associated with a change in contractors.

Q. Why are the changes in contractors important to this project?

A. The 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 very real justification for removal of a contractor. However, there are serious ramifications when a contractor is relieved of duty and a new contractor is brought on-board. It is simply not a matter of "handing off" responsibilities to a new contractor. There are serious risk management issues that must be addressed by not only the Company but also the new contractor. This risk management takes on an even greater significance when the design is not completed and the new contractor picks up where the previous contractor left off, as was the case in this project.

Further, as Mr. O'Connor and Mr. Stall commented, the project design was accomplished in parallel to the licensing activities and the construction activities. The Engineer(s) and the Engineering Company cannot simply assume that previous designs or designs in progress were performed to meet all codes and requirements by all regulatory bodies that have jurisdiction. These personnel and firms must, by requirement of their individual and Company professional licensure and liability insurance, review, reanalyze, and reaffirm that any completed design or partial design to be used in the project meets all professional and regulatory requirements. Otherwise, the Company and the new contractor are at extreme risk of liability claims throughout the life of the project and not just in the area where they have been involved during the LCM/EPU project. This liability extends to other areas of the plant that integrate with the LCM/EPU project as claims can be made that absent the LCM/EPU there would not have been this exposure. With this expansion of risk management exposure, the new contractor must mitigate this risk by spending considerable time to reassess and analyze the position it faces as it takes over from the previous contractor. Such changes and processes take considerable time, which impacts the overall project schedule.

Q. When did these contractor changes happen with the Monticello project?

A. In the Monticello case, this occurred at least two significant times, in 2010 and 2011 as noted above. Therefore, considerable delays occurred as a result of these contractor changes. These delays cost considerable dollars and could have been mitigated with proper Company oversight and project management controls.

Q. Were there other changes that affected the cost overruns?

A. Yes. Xcel's project management team suffered its own set of difficulties that impacted the overall project schedule and budget. Mr. O'Connor reflects on the issue of project management skills and effectiveness in his testimony:

> As we moved through 2010, we began to face design challenges and a need for greater oversight of quality issues. We reacted well by quickly responding to concerns, developing design solutions, establishing recovery plans for the 2011 outage and eventually changing the management structure following the 2011 outage.

Mr. O'Connor further stated that "the change was appropriate but it did not reduce costs. In fact the 2013 outage experienced substantial[ly] longer up front planning and design still took longer and cost more than we had forecast." Xcel Ex. ___ at 63 (O'Connor Direct).

Unfortunately, this result occurs in many projects that incur substantial planning problems from the beginning due to lack of proper management controls and an overly aggressive schedule, such as the expedited approach Xcel used with Monticello, as discussed in Dr. Jacob's testimony and as I discuss further below.

Q. When where the warning signs of the cost increases at Monticello first realized?

A. Based on Company documentation, it appears that as early as 2006, even before Xcel submitted the CN with the Commission, there were severe signs of schedule and budget impacts. At that time, the site project group recommended $89.5 million more for the cost for the project, based on facts of which they were aware at that time, than Xcel's Board of Directors allowed:

> The feasibility study was redone by GE **[TRADE SECRET DATA HAS BEEN EXCISED].** Results were documented in GENE-0000-0050-8232, Extended Power Uprate Cost Scoping Assessment, in May of 2006. Two schedules were considered with one doing major modifications in 2009 and 2011 and the second showing major modifications in 2011 and 2013.
>
> Total cost was estimated as GE **[TRADE SECRET DATA HAS BEEN EXCISED]** installed for those items required to implement EPU.
>
> Following consideration of the GE study, the site projects group in July of 2006 recommended a budget of $362.5M with final implementation in the 2013 RFO. *The higher cost was to recognize the uncertainty associated with work scope and estimate quality.* The Xcel Board of Directors approved a $273M budget with a 2011 project completion in August of 2006. (*Emphasis added*)

DOC Ex. ___ at MWC-3 (Crisp Trade Secret Direct)

Q. Please list the warning signs of cost increases that you observed.

A. During October of 2011, an internal status document was prepared at the request of the then-Chief Nuclear Officer, Mr. Dennis Koehl, seeking "input on the Project structure and opinions on the best way to proceed forward to complete the installation." DOC Ex. ___ at MWC-3 (Crisp Trade Secret Direct). This document details in chronological order the issues that occurred.

The early cost estimate to implement the EPU was completed in 2004 by **[TRADE SECRET DATA HAS BEEN EXCISED]**

and provided a "high" cost of **[TRADE SECRET DATA HAS BEEN EXCISED].**

A revised estimate in 2006 estimated the project at **TRADE SECRET DATA HAS BEEN EXCISED].** This estimate was performed by the GE **[TRADE SECRET DATA HAS BEEN EXCISED].**

The GE estimate was provided to the Monticello Site Projects Group that, as noted above, recommended the budget be expanded to $362.5 million due to uncertainty with work scope and estimate quality and recommended the installation occur during the 2013 refueling outage (RFO). However, without explanation, the Xcel Board disregarded the Monticello Site Projects Group, approving a budget that was substantially (33 percent) lower than the amount recommended by the "boots-on-the-ground" Team. Further, the Board of Directors required the installation to occur in 2011, 2 years earlier than recommended by the Monticello Site Projects Group, thus requiring a "fast track approach." DOC Ex. ___ at MWC-3 (Crisp Trade Secret Direct)

Q. What do you conclude from this information at the beginning of the project?

A. Regardless of the ultimate accuracy of the initial cost estimate provided by an outside entity, the Monticello Site Projects Group, or the budget approved by the Xcel Board, it is clear that there were significant issues with escalating costs and scheduling issues as early as 2006. The discussion also points to a concern about communication between the Board of Directors and the Monticello Site Projects Group since the Monticello Site Projects Group's recommendation was overruled by the Board.

Q. Where there other signs of escalating budgets?

A. Yes. The escalating budget issues continued each year from 2006 through 2011, the completion date of the EPU Cost History document prepared for Mr. Koehl. Disregarding the actual cost increases in the instant discussion, the effect of a lack of project controls on cost increases, "scope creep," (expansion of scope) and scheduling issues should have set off a significant warning to Xcel that Project Management and Project Controls were severely lacking with regards to execution of this project.

Thus, in the category where Xcel and its contractors had the most information and the most control, the scope increase, budget increase in implementation and schedule impacts should have been under better control.

Q. What were the specific problems caused by this inadequate control over the project?

A. Xcel's internal document identified numerous Project Risks Related to Cost issues that, as a whole, points to a dysfunctional Project Management program. Each one of these points is significant; aggregating these issues presents a hurdle that is nearly insurmountable unless there is proper management of a project of this size and technical difficulty.

1) Initial Scope and Schedule Were Inadequate

a. As discussed above, in 2006 the Board approved a much lower budget for the project than the site Project Team recommendation.

b. Also as discussed above, the Board approved a "fast track" approach compared to the recommendation by the site Project Team. As stated in Xcel's internal document, this decision made all work activities "fast track" with "little ability to meet outage milestones." Further, "There were insufficient experienced, qualified personnel to manage workload of doing two outages at once."

c. Xcel's internal document also indicated that "Engineering and construction costs were poorly estimated and resulted in significant overruns and delays. The ability to complete work in a timely fashion contributed to this issue." DOC Ex. ___ at MWC-3, page 3 (Crisp Trade Secret Direct)

2) Scope Control

a. Xcel's internal document identified "The use of **[TRADE SECRET DATA HAS BEEN EXICSED]**

defeated the ability to obtain detailed bids for each modification and locked in modification scope suggested in the Cost Scoping Study."

b. Xcel's internal document also pointed out that "The EPU project team/site comments on the GE purchase order were not incorporated into the contract." DOC Ex. ___ at MWC-3, page 3-4 (Crisp Trade Secret Direct)

These issues are all consistent with results that occur when a project has project management issues. Xcel's internal document goes on to establish additional issues affecting budget and scope. These are listed below:

3) **Lack of Site Ownership**

   a. Not using operational experiences recommended by the EPU Team organization

   b. Very limited capability for the project team to obtain a scope change decision that balanced scope and cost.

   c. The site did not have cost ownership of the budget. DOC Ex. ___ at MWC-3, page 4 (Crisp Trade Secret Direct)

4) **Insufficient Project Controls**

   a. Changes to scope with an appropriate consideration of cost were challenged by "fast track" schedule.

   b. The expected cost impact was not reviewed by appropriate management with requests to revisit past decisions to pursue added scope.

   c. Project did not have separate cost tracking with many projects rolling up to a single charge number. DOC Ex. ___ at MWC-3, pages 4-5 (Crisp Trade Secret Direct)

Each and every one of these issues identified by Xcel's internal document and relayed to the then-Chief Nuclear Officer, Mr. Koehl, reflects that there was not a well-structured project management plan for this project.

Q. Please describe the impacts to the overall LCM/EPU cost due to the lack of quality project management.

A. Due to Xcel's methods of tracking costs, it is not possible to separate the costs attributed to poor project management and execution from the costs associated with the specific engineering design and construction costs without (at least) exhaustive forensic accounting analysis. As was discussed in Xcel's internal document (Section 4.c. Page 5 of 5) and confirmed by Mr. O'Connor in his testimony (Xcel Ex. ___ at 28, Line 4, O'Connor Direct), the accounting of cost by categories and work orders was not sufficiently detailed to accommodate a proper accounting reconciliation, certainly not at the time of the expenditures. As a result, in this proceeding, Mr. Jacobs identifies the levels of costs reasonably attributable to the LCM and EPU.

Q. Were project management issues a cause of cost overruns?

A. Yes, without a doubt, the inability to properly manage the scoping, the general contractor, GE and its subcontractors, staffing issues and the various complexity issues which should have been identified prior to any engineering design caused the project to experience increased costs.

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.

Q. Please describe the issue of the lack of contingencies in the original budget and throughout the various budget updates.

A. The use of contingencies in a design/construction budget is a method to recognize the unknowns in the schedule and budgets. It is typical for preliminary budgets, those budgets developed during the conceptual phase of a project, to include significant budget contingencies due to all of the unknowns associated with a conceptual design. At this time in a project planning process there is very little if any actual design completed; certainly there has been no budgetary documentation developed on the pricing of equipment or on the actual construction. The potential for substantial cost variations at this point is very high. As the LCM/EPU project moved through the process used by Xcel, the 30%/60%/90% method, the contingencies could have been reduced due to the fact that more and more of the project was becoming clear and well defined.

Unfortunately, Xcel, apparently chose not to use contingencies, or else did not take the necessary time to identify the important, costly details of the project, for some reason that is still unclear to me.

Q. Are you aware of any changes the Company may have made that would improve project management?

A. I am aware that the Company has in-place at this time a document and a guiding principle that could have prevented or minimized many, if not all, of the Project Management issues that plagued the LCM/EPU project, had this policy been in-place at the beginning of the LCM/EPU project and had the Company instilled the culture described in the document. This document is the "Configuration Management" that is Xcel Ex. ___ at TJO-1 Schedule 3 (O'Connor Direct). However, the document does not have a date when it was published or when it was included in the Xcel Policy and Procedures library, so it is not clear when the document was prepared. Further, the document does not define or describe how the Principles and Behaviors were or are to be communicated to Xcel employees and how Xcel intends to monitor the establishment of this new culture. Therefore, without confirmation that this is the newly embedded culture of Xcel it cannot be determined if LCM/EPU issues are in the past.

Q. Mr. Crisp, are you aware that the NRC recently raised concerns with the degraded performance at the Monticello Nuclear Plant? If so, what is your response?

A. I am generally aware of the management issue but have not studied the basis for the NRC decision. My testimony focuses on the project management issues centered on the cost overruns. It is my understanding that DOC witness, Ms. Campbell, addresses this issue in her testimony.

Q. Does this conclude your testimony?

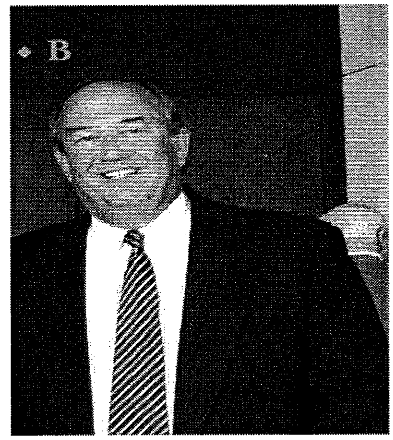
A. Yes.

Mark W. Crisp, PE
Managing Consultant

Global Energy & Water Consulting, LLC

MARK W. CRISP - PROJECT MANAGER

Mark W. Crisp is Managing Consultant with Global Energy & Water Consulting, LLC. His 35+ years of experience in the electric and water utility industry covers most functional areas of these utilities including **construction of electric generation & transmission, operations, utility economics, regulatory compliance, policy and prudence**. He has managed projects ranging from a few millions dollars to well over $9 Billion. He is recognized as an Expert in his fields throughout the US and the International community including electric restructuring, generating resource selection, renewable energy in the form of biomass, wind, PV, and hydro. He is regularly engaged to provide immediate solutions. He has successfully guided clients through such issues as wholesale and retail electric accounting issues, unbundling of services, FERC open access transmission, integrated resource planning ("IRP"), FERC and NRC licensing, as well as, fuel hedging strategies. Mr. Crisp is a recognized expert on utility issues and has provided expert witness and testimony before several state regulatory bodies, the FERC, the NRC, Federal and State courts, and the US Congress.



Mr. Crisp has completed engagements with El Paso Electric in their analysis of costs to replace steam generators; Mississippi Public Service Commission Staff in their prudence review of preconstruction and licensing costs for Grand Gulf; and Lead Consultant on the Team, including Dr. Jacobs, to evaluate the prudence of the Base Load Application of SCE&G for its V. C. Summer Units 2 & 3 nuclear project. Mr. Crisp is a "hands-on" consultant having spent 20 years of his career working for Electric Utilities. His experience includes clients and projects around the world. The following sample of engagements is indicative of Mark's diverse skills and breadth of experience.

- **State Regulatory bodies in Arizona, Connecticut, Georgia, Maryland, South Carolina, Mississippi, Arizona and Utah**
- Southeastern Federal Power Customers (Group of Electric Cooperatives and Municipal Electric systems throughout the Southeastern US)
- El Paso Electric Company -Palo Verde Nuclear
- Northeast Utilities
- Niagara Mohawk
- City of Walla Walla, Washington
- City of LaGrange, Georgia
- City of Litchfield Park, Arizona
- City of North Little Rock, Arkansas
- City of Ocala, Florida
- Office of Regulatory Staff State of South Carolina - V. C. Summer Units 2 &3 Prudence Review
-
- International Privatization of Utility Assets in Argentina, Brazil, Chile, Ecuador, Nicaragua, Australia and Europe
- Puerto Rican Electric Authority ("PREPA")
- Tennessee Valley Authority ("TVA") - Bellefonte, Watts Bar & Browns Ferry
- South Texas Electric Cooperative ("STEC")
- GLOBALCON Holdings
- Highland Nigeria Limited
- Highland Energy Solution Services Limited
- Oglethorpe Power Corporation ("OPC")
- Grand River Dam Authority ("GRDA")
- US DOE and US DoD
- Utility Privatization for Marine Corps and Navy Bases throughout California, Arizona and Nevada

Mark W. Crisp, PE

Managing Consultant

Mark has Bachelor degrees in Civil and Electrical Engineering from the Georgia Institute of Technology ("Ga. Tech") along with Master of Business Administration (Finance and Accounting) from the University of Arkansas at Little Rock.
Mark is a registered professional engineer in the States of Georgia, Florida and South Carolina.

Power Plant Experience:
Nuclear Power Generating Facilities
Plant Vogtle – Georgia Power Company (Southern Nuclear)
Plant Hatch – Georgia Power Company (Southern Nuclear)
Plant Farley – Alabama Power Company (Southern Nuclear)
Palo Verde – Arizona Public Service and Joint Owners
North Anna Power Station – Dominion Resources
Bellefonte – Tennessee Valley Authority
V. C. Summer – South Carolina Gas & Electric

Coal-fired Generating Facilities
Plant Bowen – Georgia Power Company
Plant Branch – Georgia Power Company
Plant Hammond – Georgia Power Company
Plant McDonough – Georgia Power Company
Plant Mitchell – Georgia Power Company
Colbun System – Chile S.A.
Mejionelles – Chile S.A.
Puerto Rican Electric Power Authority San Juan, Puerto Rico

Hydro-electric Generating Facilities (Domestic)
Wallace Dam – Georgia Power Company
Sinclair Dam – Georgia Power Company
Rocky Mountain Pumped Storage Project – Georgia Power Company
Bartlett's Ferry Dam – Georgia Power Company
Oliver Dam – Georgia Power Company
Jackson Dam – Georgia Power Company
Allatoona Dam – U.S. Army Corps of Engineers
Buford Dam – U.S. Army Corps of Engineers
Carter's Dam – U.S. Army Corps of Engineers
Hartwell Dam – U.S. Army Corps of Engineers
Richard Russell Pumped Storage Project – U.S. Army Corps of Engineers
Strom Thurmond Dam – U.S. Army Corps of Engineers
West Point Dam – U.S. Army Corps of Engineers
W. F George Dam – U.S. Army Corps of Engineers
Jim Woodruff Dam – U.S. Army Corps of Engineers
Wolf Creek Dam – U.S. Army Corps of Engineers
Center Hill Dam – U.S. Army Corps of Engineers
Texoma Dam – U.S. Army Corps of Engineers
Dennison Dam – U.S. Army Corps of Engineers
Amistad Dam – International Boundary Waters Commission
Falcon Dam – International Boundary Waters Commission

Hydro-electric Generating Facilities (International)
Alicura - Argentina
El Toro - Argentina

Piedra del Aquila - Argentina
El Chocon - Argentina
El Chanar - Argentina
Cerros Coloradas - Argentina
Los Reyunes - Argentina
Copalar – Nicaragua
Undeveloped Sites in Sub-Saharan Africa
El Tigre - Argentina
Los Nihuiles - Argentina
Pichi Picun Lefue - Argentina
Yacereta – Argentina & Paraguay
Itaipu – Argentina – Paraguay
Undeveloped Sites in Ecuador

Renewable Energy Projects (Domestic)

Milam Tennessee – Waste to Energy - Green Power Inc.
Wyoming Wind
Milledgeville, GA. Waste To Energy and PV - SolarZone, LLC

Renewable Energy Projects (International)

Haiti Reconstruction
Lagos, Nigeria WTE
Nigeria Transitional Gas Power Plant

Testimony and Expert Witness

State of Arizona Corporation Commission
State of South Carolina Public Service Commission
State of Georgia Public Service Commission
State of Mississippi Public Service Commission
State of Maryland Public Service Commission
State of Utah Public Utilites Commission
Federal Energy Regulatory Commission
Nuclear Regulatory Commission
United States Congress
Federal District Court of Washington D.C.
5th Circuit Court of Appeals – Washington DC
Federal District Court in the Northern District of Georgia
Federal District Court in the Northern District of Alabama
US Court of Appeals - 11th Circuit

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Gary Van Middlesworth Vice President Fleet Standardization	700 First Street Hudson, Wisconsin 54016
Dave Wilson Vice President Assessment	700 First Street Hudson, Wisconsin 54016

Legal Counsel

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1.3.4 Class of License, Use of Facility, and Period of Time for which the License is Sought

NMC requests renewal of the Class 104b operating license for the Monticello Nuclear Generating Plant (Facility Operating License DPR-22) for a period of 20 years beyond the expiration of the current license. This would extend the operating license from midnight September 8, 2010, to midnight September 8, 2030.

This application includes a request for renewal of those NRC source material, special nuclear material, and by-product material licenses included within the current operating licenses and issued pursuant to 10 CFR Parts 30, 40 and 70.

The facility will continue to be known as the Monticello Nuclear Generating Plant.

1.3.5 Earliest and Latest Dates for Alterations, if Proposed

NMC does not propose to construct or alter any production or utilization facility in connection with this renewal application. The current licensing basis (CLB) will be continued and maintained throughout the period of extended operation.

EPU Cost History

2004 – First full EPU cost study completed by [redacted] Project resulted in a high cost estimate of [redacted].

2006 – The feasibility study was redone by GE [redacted]. Results were documented in GENE-0000-0050-8232, Extended Power Uprate Cost Scoping Assessment, in May of 2006. Two schedules were considered with one doing major modifications in 2009 and 2011 and the second showing major modifications in 2011 and 2013.
Total cost was estimated as [redacted] installed for those items required to implement EPU.

Following consideration of the GE study, the site projects group in July of 2006 recommended a budget of $362.5M with final implementation in the 2013 RFO. The higher cost was to recognize the uncertainty associated with work scope and estimate quality. The Xcel Board of Directors approved a $273M budget with a 2011 project completion in August of 2006.

The GE Phase 1 PO was issued on 9/8/06 to allow start of licensing activities. The GE Phase 2 PO was issued on 12/21/06 to allow start of work on GE scope modification activities.

2007 – In 2007 project cash flow was very near budget and total project costs were projected to increase by $6M. Primary issues during 2007 were MISO grid studies, steam dryer analysis, main steam line monitoring to define steam dryer loads and RFP studies.

2008 – Costs for 2008 were $9.6M over predicted values for the year. Costs were above base EPU projections for condensate demin panel upgrade, RWCU upgrade, *fuel pool heat exchangers,* Main Steam and FW Piping Upgrade, Moisture Separator drains, stator cooling heat exchanger, 1AR, *summer derates*, *SJAE Valve upgrades*, turbine instrumentation upgrades, *circ water and cooling tower upgrades*, *under vessel cables* and 50% of capacitor banks. In addition, no money was in the budget to cover implementation preparations for the 2009 RFO. <u>Italicized projects were dropped from the final scope in an attempt to balance the budget as cost increases continued.</u>

Based on Budget Create, a final project completion budget of $49.4M above the original $273M budget was required when including the steam dryer replacement and 13.8 kv modifications (approved by the Financial Council in December). The increase was due to increased spending in 2008 and the increased authorization for 13.8 kv and steam dryer.

2009 – Costs for 2009 were $28M above projected based on Budget Create at end of 2008. Major costs included the refueling outage being $10.5M above predicted values (delta's to predicted were [redacted], materials - $1.2M and plant direct - $1.2M). Cost issues are not specifically identified but major activities were main transformer, PRNM, turbine replacement, CARV replacement and steam dryer preparation.

The projected total project cost increased by $39.4M based on Budget Create from 2008 to 2009. Most of this increase was due to 2009 expenditures being $28M above predicted. CARV replacement was significantly more complicated then anticipated due to limited ability to as-built the system from radiation levels.

2010 – Costs for 2010 were $6.2M above predicted values with reasons for cost increases not specifically identified. Major ongoing work activities were 13.8 kv, RFP work and main transformer. Cost of moving 13.8 kv and RFP modifications from GE to other vendors was major portion of impact.

EPU Cost History

The projected total project cost increased by $49.9M based on Budget Create from 2009 to 2010.

2011 – Costs for 2011 were $164.7M year to date (10/13/11). This is $43.3M above the year end projected cash flow from Budget Create at end of 2010.

[redacted] over predicted values for work performance when considering the fact that significant work was removed from outage scope that was projected to be completed. Significant issues on outage cost and planning were major drivers to budget over runs.

Significant Work Activity Cost History

Scope	GEH Cost Scoping Study Installed Estimate	GEH Purchase Order Cost Projection	Actual Installed Costs
Licensing of EPU and MELLLA+ (GE costs only)	[redacted]	[redacted]	$25.3M
Condensate Demin with Control System Upgrade	[redacted]	[redacted]	$77.2M
Steam Dryer Replacement with Instrumentation	[redacted]	[redacted]	$39.5M
Turbine/Generator Upgrades	[redacted]	[redacted]	$59.9M
CARV Replacement	[redacted]	[redacted]	$18.4M
Main Transformer Replacement	[redacted]	[redacted]	$26.2M
PRNM Upgrade	[redacted]	[redacted]	$17.5M
FW Capacity Upgrade	[redacted]	[redacted]	$24M Final cost - $66.3M Changed to replacement of RFPs
13.8 kv Upgrades	[redacted]	[redacted]	$31.95M Final cost – TBD $70M estimate
Totals	[redacted]	[redacted]	$400.3M

*Does not include many installation items or the BOP scope for an additional $26M.

EPU Cost History

PROJECT RISK RELATED TO COST

1. **INITIAL SCOPE AND SCHEDULE WERE INADEQUATE**
   a. The Board approval of a $273M budget in August 2006 was $90M below the Project Team recommendation. The 2006 Cost Scoping Assessment was based on a limited review of possible modifications that addressed identified pinch points; the identification of pinch points was successful since few additional issues were identified. The cost estimate had high uncertainty since little engineering was done on the design concepts suggested. The NSP EPU project team position was that each project should have a more detailed review to define final scope and cost. Design and installation would be handled by bids for each modification. This would have resulted in each modification obtaining more detailed estimates as it progressed through design and installation phases to provide final cost numbers. The Project Team recommended a budget of $362.5M that reflected uncertainty in the Scoping Assessment and also the fact that GE work did not did not cover all required scope to allow implementation.
   b. The EPU project team recommended installation in the 2011 and 2013 RFOs. This was based on the amount of work required and the expected impact on site resources and capabilities. NSP Board approval was based on a 2011 implementation date. This made all work activities "fast track" with little ability to meet outage milestones. The project never caught up to work load. Ideally the project needed to be working on two outages at the same time to be able to complete required design and implementation planning work. This was not successful. Work on the subsequent outage always lagged until completion of the current outage with an additional schedule impact after the outage for "rest and recovery". There were insufficient experienced, qualified personnel to manage workload of doing two outages at once. This resulted in outage milestones being challenged.
      i. Engineering and construction costs were poorly estimated and resulted in significant overruns and delays. The inability to complete work in a timely fashion contributed to this issue.
2. **SCOPE CONTROL**
   a. The use of [redacted] defeated the ability to obtain detailed bids for each modification and locked in preliminary modification scope suggested in Cost Scoping Study. The work prior to GE contract issuance did not include any detailed engineering and had very limited site input. Requests during the Cost Scoping Study for site involvement were unsuccessful since <6 hours of site input was provided. This resulted in a project scope defined by firm price contract that had a defined scope that had not been agreed to by the site. Use of the estimate, design and installation phases for design approval typical of other design/project work would have provided an opportunity for site input.
   b. The EPU project team/site comments on the GE purchase order were not incorporated into the contract. Issues on scope and wording were provided. Only some of these comments were addressed by NMC management that controlled the contract negotiations. Many were dropped since insufficient time was available to negotiate solutions with GE. This led to the need for the site to create many modifications around the base scope in the GE contract to allow installation to occur, i.e. fire protection, logic, structural issues, interferences, etc. These

were typically covered by NSP since additional scope could be completed more cost effectively then using GE. This required the addition of significant design engineering and project management resources beyond original project staffing plans for these groups.

c. The steam dryer budget did not include disposal of the original steam dryer or removal of steam dryer instrumentation. Not including these costs did not provide a full picture of costs.

3. **LACK OF SITE OWNERSHIP**

   a. Not using operational experience that recommended EPU team organization contributed to scope changes and strained project resources for responding to potential design issues. Benchmarks and BWROG NEDO-33159 Guidance suggested staffing of EPU project teams with "a dedicated site team reporting to site senior management. This will ensure site ownership of the project. Staff the project sufficiently to minimize the effect on routine site resources. Use best available site personnel for the team. Fill their original positions with contractors if needed. This will help ensure that expertise gained from the project is not lost."

   b. There was very limited capability for the project team to obtain a scope change decision that balanced scope and cost. The project principle to enhance equipment margins became a reason to change scope. Reviews during Site Steering Committees and design review meetings often led to increased scope. In 2007 the modifications defined by contract were brought to the Site Steering Committee to insure site management team acceptability since there had been no site involvement in the Cost Scoping Assessment. The most significant scope changes from this review were decisions to essentially replace the full condensate demin system and a requirement to switch from a supplemental RFP to an upgrade to the capacity of the reactor feedwater pumps. RFP replacement eventually led to the 13.8 kv upgrade. These large cost changes did not appear to be approved by management in any detail. Part of the reason for this was that schedule restraints forced parallel work and required significant cost commitments to be made to achieve goals.

   c. The site did not have cost ownership of the budget and plant desired scope was added without the cost impact of the changes being known. Site Steering Committee review meetings resulted in significant scope being added due to this. Examples include all condensate demin valves, turbine expansion joints, redundancy for isophase bus, selected cable replacements, #13 feedwater heater replacement, stator water cooling heat exchanger replacement, RWCU capacity improvements and turbine generator vibration system upgrade.

4. **INSUFFICIENT PROJECT CONTROLS**

   a. Changes to scope with an appropriate consideration of cost were challenged by "fast track" schedule. The modification to upgrade the original RFPs was given to [redacted] that included engineering and material procurement for a price of [redacted] There were no activities to cover project cost estimating or approval of engineering phase costs. This resulted in the loss of management approval for these cost items. Poor performance [redacted] eventually led to the transfer of this work to NSP in 2010 with decisions to have other contractors perform the work.

EPU Cost History

b. The expected cost impact was not reviewed by appropriate management with requests to revisit past decisions to pursue added scope if scope costs were large. Costs were reflected in Budget Create numbers for the next calendar year and in communications with management prior to Budget Create.

c. Projects did not have separate cost tracking with many projects rolling up to a single charge number. Not having a budget by project resulted in a challenge to project managers to be able to control and forecast cost. This also allowed changes in scope to be "covered" by deleting selected projects. The low level of cost tracking that resulted from having one bucket for many projects was insufficient to allow early identification of cost issues. Management attention was not applied to address these issues.