BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
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IN THE MATTER OF A COMMISSION INVESTIGATION INTO XCEL ENERGY'S MONTICELLO LIFE CYCLE MANAGEMENT AND EXTENDED POWER UPRATE PROJECT AND REQUEST FOR RECOVERY OF COST OVERRUNS	MPUC Docket No. E002/CI-13-754 OAH Docket No. 48-2500-31139

SURREBUTTAL TESTIMONY AND ATTACHMENTS OF NANCY A. CAMPBELL

ON BEHALF OF

THE DIVISION OF ENERGY RESOURCES OF
THE MINNESOTA DEPARTPARTMENT OF COMMERCE

SEPTEMBER 19, 2014

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I. INTRODUCTION

Q. Would you state your name, occupation and business address?

A. My name is Nancy A. Campbell. I am employed as a Public Utilities Financial Analyst by the Minnesota Department of Commerce, Division of Energy Resources (DOC or Department). My business address is 85 7th Place East, Suite 500, St. Paul, Minnesota 55101-2198.

Q. Are you the same Nancy A. Campbell who submitted Direct Testimony earlier in this proceeding?

A. Yes.

II. PURPOSE

Q. What is the purpose of your testimony?

A. The purpose of my Surrebuttal Testimony is to respond to other parties' Rebuttal Testimony regarding the issues I raised in my Direct Testimony. Specifically, I respond to the following Rebuttal Testimony witnesses from Northern States Power, d/b/a Xcel Energy (Xcel or the Company) and from the Office of Attorney General – Antitrust and Utilities Division (OAG-AUD):

- David Sparby, Company witness who addressed Monticello Prudency, Oversight, and Policy;
- Timothy O'Connor, Company witness who addressed Final Program Costs, Recent Nuclear Regulatory Commission (NRC) Issues, Program Management, and Separation Analysis between the Life Cycle Management (LCM) and Extended Power Uprate (EPU);

- James Alders, Company witness who addressed Resource Planning and Project Economics;
- Richard J. Sieracki, Company witness who addressed Project Management Prudence;
- J.A. Stall, Company witness who addressed Project Scope and Design; and,
- John Lindell, OAG-AUD witness who addressed the Monticello LCM & EPU Projects Overall.

Q. How have you organized your Surrebuttal Testimony?

A. I organized my Surrebuttal Testimony by topic and summarized witnesses' comments on each topic. The following are the topics I address:

- Continuing human performances concerns by the NRC at both the Monticello and Prairie Island (PI) Nuclear Plants;
- Overstatement of Benefits by the Company for Monticello LCM and EPU Projects;
- Separately filed and approved certificates of need (CNs) with separate costs estimates for Monticello LCM and Monticello EPU Projects, which clearly support a need for separate accounting and tracking of the costs for both Monticello LCM and Monticello EPU Projects;
- Budget problems and cost overrun amounts for Monticello LCM and EPU Projects;
- Lack of communication by the Company regarding the cost overrun with the Commission and interested parties;

- Prudency concerns and forensic accounting analysis;
- Reasonableness of Department's recommendations; and,
- Summary of Department's and AUD-OAG's recommended adjustments.

III. CONTINUING HUMAN PERFORMANCE CONCERNS BY THE NRC

Q. How did Mr. Sparby respond to your comments regarding performance concerns raised by the NRC for the Monticello nuclear plant?

A. First, he indicated that the Company takes NRC concerns very seriously and the safe operation of the Monticello nuclear plant is the Company's top priority. He then referenced Mr. O'Connor's Rebuttal Testimony to further explain that these NRC activities do not reflect poor performance or safety at the Monticello plant. Mr. Sparby concluded that the Monticello plant is in a healthy condition and modifications made during the LCM and EPU projects have positioned the Company to provide an additional 20 years of service from this plant. NSP Ex. ___ at 29 (Sparby Rebuttal).

Q. What information did Mr. O'Connor provide regarding performance concerns raised by NRC for the Monticello nuclear plant?

A. Mr. O'Connor addressed the NRC concerns, and reemphasized that none of the concerns raised by NRC constitute safety violations or create risk to the community. He also noted that the Company is taking the NRC compliance obligations very seriously. Mr. O'Connor addressed the external flood control issue that resulted in a "yellow" finding from NRC, indicating that the Company has done necessary work to address this flood issue and is awaiting a follow-up NRC inspection to resolve the issue. NSP Ex. ___ at 33-34 (O'Connor Rebuttal).

Q. What other NRC concerns did Mr. O'Connor address?

A. He discussed the weld inspection issue and human performance issues that I noted in my direct testimony in which the NRC has raised (along with the external flood control issue) at the March 31, 2014 public meeting. DOC Ex. ___ at 3-4 (Campbell Direct). Regarding the Monticello weld inspection issue, he provided the following explanation:

> 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.
> NSP Ex. ___ at 35 (O'Connor Rebuttal).

Q. What was Mr. O'Connor's response regarding the human performance issues?

A. He noted that the human performance issues stem from several examples where human performance contributed to findings of low safety significance identified by the NRC. However, in aggregate, he acknowledged that the NRC determined that these issues crossed a threshold for what the NRC calls a Substantive Cross-Cutting finding in the area of human performance. He noted that the performance concerns were determined to be manifested in inadequate procedure and work instructions preparation and usage, attributed to loss of experience and skills with the Operations Department. He also noted interim actions have been put in place by Monticello to bridge the gaps going forward, such as additional Control Room Oversight and coaching. Finally, he noted that contractor procedure usage was another area of human performance; he indicated that supplemental workers had less experience, which contributed to issues at the last Monticello EPU refueling outage. NSP Ex. ___ at 35-36 (O'Connor Rebuttal).

Q. Does the NRC continue to have ongoing concerns with human performance concerns at both the Monticello and PI Nuclear Plants?

A. Yes. While I believe Xcel is attempting to remedy the issues, I note that, as the two recent NRC letters attached to my surrebuttal testimony indicate, both dated September 2, 2014, NRC continues to note the ongoing human performance concerns based on mid-cycle performance review by NRC of PI and Monticello. DOC Ex. ___ at NAC-S-1 (Campbell Surrebuttal).

Q. What specific concerns has the NRC raised in the September 2, 2014 letter for the Monticello Nuclear Plant?

A. The NRC again noted the Yellow finding related to the failure to maintain a procedure addressing all of the effects of an external flood scenario on the plant. Specifically, NRC identified the failure of the Company to be able to support timely implementation of flood protection activities within the 12-day timeframe stated in the safety analysis report. Specifically, NRC noted the following concerns related to the Monticello Nuclear Plant:

> The NRC identifies substantive cross-cutting issues (SCCIs) to communicate a concern with the licensee's performance in a cross-cutting area and to encourage the licensee to take appropriate actions before more significant performance issues emerge. The NRC identified a cross-cutting theme in the Human Performance, Conservative Bias aspect (H.14). Specifically, five inspection findings for the current 12-month assessment period were a cross-cutting aspect of H.14, "Individuals use decision-making practices that emphasize prudent choices over those that are simply allowable." The NRC determined that an SCCI exists because the NRC has a concern with your staff's scope of effort and progress addressing the cross-cutting theme associated with Human Performance, Conservative Bias (H.14). Specifically, the NRC noted that your staff missed an early opportunity to identify this SCCI and, therefore failed to recognize that the SCCI affected overall plant performance. As a result, corrective actions to address the SCCI were unnecessarily delayed resulting in continued, declining performance in this area.
>
> In October 2013, after an adverse trend was identified in your corrective action program for three NRC-identified issues associated with this cross-cutting aspect, your staff determined that an apparent cause evaluation was necessary to address this issue. The apparent cause evaluation was subsequently cancelled and justifications were determined to be incorrect and delayed full understanding of the significance of the lack of conservative bias in decision making until April 2014, after another three NRC-identified findings with related H.14 aspects had been identified during the first quarter 2014. In total, six NRC-identified findings with H.14 aspects had been identified between February 2013 and April 2014. In May 2014, your staff completed a root cause evaluation which concluded that these issues reflected current organizational behavior and resulted

> from inadequate decision making and delayed corrective action from prior, similar issues. In particular, the root cause evaluation noted that the failure to take corrective actions in October 2013 was a result of underlying organizational behaviors. Given these circumstances and the recency of your additional actions, we cannot conclude that the corrective actions will be fully effective in addressing the cross-cutting theme.
>
> This human performance SCCI will remain open until the number of findings with a cross-cutting aspect of H.14 is reduced, the corrective actions taken to mitigate the cross-cutting theme prove effective, and sustained performance improvement is observed in the H.14 aspect of the human performance area. The NRC will monitor your staff's effort and progress in addressing the SCCI by evaluating your corrective action program, any root cause evaluations for the SCCI, and performance improvement initiatives.

The NRC also noted additional inspections by the NRC, beyond Routine inspections, through December 31, 2015. DOC Ex. ___ at NAC-S-1 (Campbell Surrebuttal).

Q. Are you surprised by the ongoing problems the Company continues to have with the NRC regarding human performances concerns?

A. Yes. As noted in my Direct Testimony, the Company noted at the March 31, 2014 public meeting and in response to Department information request 116 that these NRC human performance issues were being addressed. The NRC letter above noted that Xcel provided information in May, 2014, but the NRC appears far from satisfied based on the above cited comments from the NRC's September 2, 2014 letter regarding Monticello. DOC Ex. ___ at NAC-2 (Campbell Direct) and DOC Ex. ___ at NAC-S-1 (Campbell Surrebuttal).

Q. Do the concerns raised by NRC result in increases to overall costs of nuclear costs?

A. Yes, in my view. Clearly nuclear operations costs will be higher due to increased NRC review and required responses to NRC, including additional NRC inspections. Another clear example of higher costs is the weld cask test issue that the Company and the Company's vendor did incorrectly as noted in my Direct Testimony in my Background Section and that Mr. O'Connor discussed above. Certainly, costs related to the Company having to figure out an alternative method to address the post-weld issue, plus requesting an exemption from the NRC are increasing nuclear costs.

Another example is the human performance error that contributed to the NRC's concerns regarding the EPU power ascension testing, as discussed on pages 51-57 of my Direct Testimony and on pages 46-53 of my Surrebuttal Testimony in the current Xcel Rate Case in Docket No. E002/GR-13-868.[1] For example, this human performance wiring error appears to have contributed to the EPU likely not being available until 2015.

In conclusion, clearly nuclear costs are unnecessarily increased when the Company has to redo its work, determine alternative ways to address incorrect welding, and ask for NRC exemptions, rather than performing work correctly the first time.

The record in this case reflects a theme of Xcel hurrying up to perform tasks without ensuring that the tasks are performed correctly and, thus, having to correct mistakes by having to redo work. Xcel's actions in this regard clearly contributed to

[1] A copy of all referenced pages and attachments of my testimony from the current Xcel rate case have been attached to this testimony as NAC-S-2.

the higher costs, more than double the CN estimated costs, for the Monticello LCM and EPU projects. DOC Ex. ___ at NAC-S-2 (Campbell Surrebuttal).

IV. OVERSTATEMENT OF BENEFITS BY THE COMPANY FOR MONTICELLO LCM AND EPU PROJECTS

Q. What are the Company's statements regarding benefits for the Monticello LCM and EPU Projects?

A. On pages 4 and 21 of his Rebuttal Testimony, Mr. Sparby stated that the Monticello LCM and EPU projects provided benefits of 671 MW of generation and 20 years of carbon-free baseload generation. NSP Ex. ___ at 4, 21 (Sparby Rebuttal).

Q. Do you have concerns and corrections regarding these statements?

A. Yes. First, the Monticello Plant continues to operate at the 600 MW pre-EPU level, not at 671 MW. As I noted in my Opening Hearing Statement on page 3 in the current Xcel Rate Case (Docket No. E002/GR-13-868), Xcel did not show that the Monticello EPU (approximately 71 MW) would likely be available in 2014.[2] As a result, the Department recommended a January 2015 assumed in-service date for purposes of ratemaking, since: 1) the EPU will likely not be available for customers in 2014 and 2) customers are already paying replacement power costs in 2014.

Second, as noted in my Direct Testimony in the current Xcel Rate Case and attached to my Direct Testimony in this proceeding as Attachment NAC-13 (specifically page marked NAC-9), for purposes of depreciation, the remaining life of

[2] I note that on September 15, 2014, Xcel filed an event report with the NRC indicating a further reduction in power output due to a "trip of the 12 Reactor Recirc Pump." See link to NRC for more details: http://www.nrc.gov/reading-rm/doc-collections/event-status/event/2014/20140915en.html

the Monticello Plant is 16.8 years as of January 1, 2014. This fact means that the Monticello EPU Project (71 MW) will likely only be available for 15.8 years assuming a January 1, 2015 in-service date for purposes of rates as recommended by the Department.

Regarding the benefits of carbon-free generation, Mr. Shaw noted in his Direct Testimony that those benefit were incorporated in the analysis conducted in the 2008 CN by applying a $17 per ton cost of CO_2 emissions. DOC Ex. ___ at 5 (Shaw Direct) Further, while I agree that a nuclear plant provides carbon free benefits, for the more limited timeframe and MWs as corrected above, I think is important to remember that nuclear plants creates nuclear spent fuel that the Department of Energy still is not taking and likely will not take for years to come. As a result, this nuclear spent fuel will need to remain in interim casks, which clearly has some environmental impacts.

Q. What other Company witness addressed benefits of Monticello LCM and EPU Projects?

A. Mr. O'Connor on page 9 and 10 of his Rebuttal Testimony stated that the NRC license is only valid until September 2030; I agree. However, he goes on to state that the NRC and nuclear industry are well underway in developing extended license policies to ensure that the extended operating plants' lives beyond 60 years (40 initially and 20 for relicense) is safe, manageable, and economical. He notes that the NRC refers to this initiative as the "subsequent license renewal" and he attached a White Paper from the Nuclear Energy Institute (NEI) discussing this initiative as

Schedule 2 of his Rebuttal Testimony. NSP Ex. ___ at 9-10 and Schedule 2 (O'Connor Rebuttal).

Q. Has Xcel shown that it is reasonable in this proceeding for the Commission to consider benefits beyond the term of the NRC license for Monticello at this time?

A. No. The question of whether the operating life of Monticello would extend beyond 2030 is far too speculative to give any weight, even with an NEI whitepaper, so the only supportable benefits are those up through 2030, per the current license.

Q. Why do you conclude that the Company is likely overstating its overall benefits for Monticello LCM and EPU projects?

A. I believe that the Company is likely overstating its benefits of Monticello LCM and EPU projects regarding the actual MWs available and the actual time period these MWs are available because the costs were so high – more than double their actual CN estimates. I conclude that the Company is attempting to find additional overstated benefits to make the Monticello LCM and EPU projects appear to be more cost-effective than they really are.

V. SEPARATELY FILED AND APPROVED CNs WITH SEPARATE COSTS ESTIMATES FOR MONTICELLO LCM AND MONTICELLO EPU PROJECTS, CLEARLY SUPPORTS A NEED FOR SEPARATE ACCOUNTING AND TRACKING OF THE COSTS FOR BOTH MONTICELLO LCM AND MONTICELLO EPU PROJECTS

Q. On pages 19, 20 and 22 of your Direct Testimony, what reasons did you give for why it doesn't make sense for Xcel to have tracked the LCM and EPU in one work order?

A. First, I noted that Xcel treated Monticello LCM and EPU projects as two separate projects for purposes of review and approval of the projects in CN proceedings before the Commission. Thus, it is not reasonable for Xcel to have tracked these costs for purposes of accounting and regulatory compliance as if they were one project.

Second, Xcel's decision to include all of the costs of the Monticello LCM and EPU projects estimated at $346 million in a single work order is not reasonable since doing so guarantees that the costs are not transparent.

Third, I noted that Xcel's choice in tracking these costs resulted in needlessly higher costs for this prudency review since it was necessary for the Department to hire a consultant to split apart what Xcel never should have put together.

Fourth, the Company's choice not to track costs separately for the Monticello LCM and EPU projects indicated the Company did not think it was important to track the costs approved by the Commission in the two separate CNs.

Fifth, the Company's child orders for modification are labeled as being EPU, yet the Company claims in this proceeding that most of the costs are for the LCM. Ratepayers are entitled to the benefit of any doubt as to Xcel's proposed showing of reasonableness and, thus, it is important to note that Xcel's selection of a non-transparent method of tracking costs appears to create significant doubt as to Xcel's claims regarding costs being attributable to one project rather than the other. DOC Ex. ___ at 19-20, 22 (Campbell Direct).

Q. Does Mr. Sparby agree with these reasons?

A. No, Mr. Sparby disagreed and provided the following reasons for his disagreement:

- First, he noted that the Company accounted for the Program (Monticello LCM and EPU projects) as an integrated initiative based on the Company's conscious decision to implement the Program in the same manner.
- Second, he noted that the premise of an integrated program was to replace older with newer equipment necessary to support the 20-year life extension as well as the uprate. Thus, he indicated that the modeling for the CN included total cost with a portion assigned to the EPU.
- Third, he stated that he does not see how the Company could have implemented the Program without combining the LCM and EPU together without substantially expanding the cost of the Program.
- Finally, Mr. Sparby concluded that it would not be appropriate to implement EPU and LCM projects separately solely to make the accounting for the incurred costs separate or easier. NSP Ex. ___ at 30-31 (Sparby Rebuttal).

Q. How do you respond to Mr. Sparby's reasons for why the Company doesn't believe they needed to separate the cost of the Monticello EPU and LCM?

A. First, I find it hard to believe that, despite the Company filing two separate CNs with two separate estimates for costs for the Monticello LCM and EPU projects that were approved by the Commission, the Company now claims that they did not have any obligation to track their costs and support their costs the way these costs were initially approved, separately. I think the Commission should be very concerned with the Company's position on this issue, and not only for purposes of this proceeding.

Second, his argument about the modeling in the CNs is not consistent with the facts that were in the two CNs. Mr. Shaw addresses this issue.

Third, I don't agree nor has he provided support for his conclusions that because the Company was implementing the LCM and EPU together this fact somehow means that the Company can't track the costs separately. The Company performs plant outages all the time for nuclear, coal and gas plants, where there are several projects done at the same time during the plant outage and are tracked in separate work orders, so I respectfully disagree with these unsupported conclusions. I have attached Department information request no. 196 in Docket No. E002/GR-12-961 as an example of the Company tracking costs for several projects in different work orders related to a spring 2012 outage for Xcel's King Plant. DOC Ex. ___ at NAC-S-3 (Campbell Surrebuttal).

Finally, I note that the statement in his rebuttal testimony is misleading since it implies that there was only one and not two separate CNs:

> The premise of an integrated Program was to replace old equipment that needed to be replaced with newer equipment necessary to support the 20-year license extension as well as the uprate. Thus, our modeling for the Certificate of Need included the total cost with a portion assigned to the EPU. I do not see how we could have implemented the Program otherwise without substantially expanding the cost of the Program.
> Xcel Ex. ___ at 31 (Sparby Rebuttal)

I might believe his concern about the higher costs of tracking the two projects separately if the Company had started with one combined CN for the LCM and EPU, with one cost estimate, and then later needed to separate the costs. In fact, that is the point I made above and in my direct testimony, that Xcel's choice to track these costs as they did resulted in needlessly higher costs for this prudency review since it was necessary for the Department to hire a consultant to split apart what Xcel never should have put together. However, Xcel's implication that there was only one CN was certainly not the case, as Mr. Shaw describes in his surrebuttal testimony.

Q. Does any other witness address the separation of the LCM and EPU projects for purposes of accounting and regulatory purposes?

A. Yes. Mr. Alders responded to my Direct Testimony where I indicated that the Company treated Monticello LCM and EPU projects as two separate projects for purposes of review and approval of the projects in CN proceedings before the Commission. He then responded by saying that from a resource planning perspective, it would have been highly inefficient and inconsistent with the Company's twin goals of preserving and increasing this generation resource for customers to pursue the LCM and EPU uprates separately. Mr. Alders also stated that much of the equipment being replaced for the LCM purposes also need to be modified for the EPU, so planning for these needs concurrently maximized use of the Company's resources. NSP Ex. ___ at 9-10 (Alders Rebuttal).

Q. How do you respond to Mr. Alders comments that from a resources planning prospective it was inefficient and inconsistent to not plan these projects concurrently?

A. First, I note that my comments in Direct Testimony were about my disagreement with the Company's arguments that they didn't or couldn't track the costs of the LCM and EPU projects, when clearly the Company had filed for two separate CN with two separate costs estimates, so of course the Company should have expected to be held accountable to the cost overruns in the same manner, as separate projects.

Second, I don't agree that it would have been inefficient and inconsistent to implement the LCM without the EPU if the EPU was not cost effective. Mr. Shaw addresses the cost effectiveness of the EPU. The Company certainly should know that they need to balance reasonable costs and benefits in a determination to acquire new resources and implement projects. Clearly, approval of the EPU did not provide the Company with a blank check to recover any cost they incurred despite poor planning, poor oversight of vendors, start and stop problems with vendors, etc., as addressed by the Department's consultants Mr. Crisp and Mr. Jacobs, and the human performance problems as I discuss above.

If the Company really believed they should still go ahead with the EPU project despite the cost increases they saw, then as soon as they were aware of the higher costs, and certainly in the NOCC in 2011 the Company should have notified the Commission and interested parties in that proceeding about expected significantly higher costs and done a rerun of their model to see if it was still cost-effective to proceed, rather than asking for recovery of all of the costs at the end of this implementation.

Q. Does Mr. O'Connor also address the use of a single work order and the Company's integrated implementation of the Commission's two separate CNs?

A. Yes. On page 11 of his Rebuttal Testimony, Mr. O'Connor noted that Company witness Mr. Weatherby in his Direct Testimony described that all the costs were initially accounted for in a single common work order. Mr. O'Connor also noted that the Governance Council/Financial Council approved the Monticello relicensing as an integrated initiative in a July 2003 presentation and additional information in August 2006 attached as Schedules 4 and 5. NSP Ex. ___ at 11 and Schedules 4-5 (O'Connor Rebuttal).

Q. How do you respond to Mr. O'Connor's comments that all the costs were accounted for in a single work order and the Governance Council/Finance Council approved the Monticello LCM and EPU projects as an integrated initiative?

A. Similar to comments above, I am very concerned that, despite the fact that the Company received approval for the EPU and LCM projects in separate CNs and with separate estimates, Xcel maintains that they didn't have an obligation to track these costs separately.

Additionally, internal decisions made by Company via the Governance Council/Financial Council to handle the Monticello LCM and EPU projects as integrated projects should not in my view overrule the Commission's approved CNs that had separate cost estimates. I also don't agree that the Company couldn't have tracked separately for the LCM and EPU projects, and in light of approved separate costs estimates, I believe that the Company had a regulatory obligation to do so.

VI. BUDGET PROBLEMS AND COST OVERRUN AMOUNTS FOR MONTICELLO LCM AND EPU PROJECTS

Q. What does Mr. O'Connor say regarding your concern with the Company's initial cost estimate of $346 million?

A. First, I note that Mr. O'Connor's question does not accurately reflect the concern I discussed in direct testimony, DOC Ex. ___ at 22-27 (Campbell Direct). Specifically, the premise in Mr. O'Connor's question was:

> 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 [footnote: Campbell Direct at 22-27]. Do you agree that this was an unreasonable certificate of need-level estimate?
> Xcel Ex. ___ at 43 (O'Connor Rebuttal)

However, that premise mischaracterizes my testimony since the focus of my cited testimony was on cost *overruns*, not the level of the initial cost estimates. I note that DOC Witness Mr. Crisp discusses Xcel's initial cost estimates for the two projects in his surrebuttal testimony.

Nonetheless, Mr. O'Connor indicated that based on the information the Company had at the time and the need to move promptly to capture the benefits for customers the $346 million estimate was reasonable. He does go on to say that the Company could have spent more time upfront and perhaps developed a better budget. NSP Ex. ___ at 43-44 (O'Connor Rebuttal).

Q. How do you respond to Mr. O'Connor's comments regarding the initial cost estimate of $346 million?

A. First, I note that Mr. Shaw addresses in his surrebuttal testimony what Xcel was required to do in the 2004 resource plan.

Second, I note that DOC Witness Mr. Crisp discussed in his Direct Testimony (DOC Ex. ___ at 28-29 and elsewhere, Crisp Public Direct) how moving promptly ("fast track") has not worked out very well for the Company or ratepayers, since the hurryup approach involving planning and design work as construction progressed (as noted by DOC's consultants) resulted in the Monticello LCM and EPU projects being significantly higher costs (specifically a 116% cost overrun).

Third, I am concerned that in past Commission proceedings the Company indicated that the Monticello plant was in good shape, as indicated in their low $345 million initial cost estimate, so that limited equipment would need replacement, resulting in initial cost estimates that did not adequately represent the costs of the projects. Yet in the current proceeding Mr. Sparby now claims that the capital investment was extensive: "We essentially rebuilt an almost-new power plant around an existing core and reactor . . . ". NSP Ex. ___ at 4 (Sparby Rebuttal).

Q. Does Mr. O'Connor appear to agree with your statement that total costs amounted to $748.1 million for the Monticello LCM and EPU projects?

A. Yes. I appreciate that he accurately summarized this aspect of my testimony on pages 10 and 11 of his Rebuttal Testimony. Specifically, my Direct Testimony referenced DOC information request 88, Attachment A which shows total costs of $752.6 million less a net reduction ($4.5 million) in estimated final costs in 2014 offset by expected vendor credits, resulting in the final total cost for Monticello LCM and EPU projects of $748.1 million on a total company basis. I also noted that the $748.1 million is comprised of $635.3 million for construction work in progress (CWIP), $28.0 million for retirement work in progress (RWIP)/removal costs, and $84.8 million for AFUDC, all on a total company basis. NSP Ex. ___ at 10-11 (O'Connor Rebutttal) and DOC Ex. ___ at 13-14 and NAC-8 (Campbell Direct).

Q. Did Mr. O'Connor respond to your request that the Company file an update on the final costs for the Monticello LCM and EPU projects?

A. Yes. Mr. O'Connor agreed to provide an update on the final costs including an explanation of any differences between the $748.1 million as of March 31, 2014 and the final costs provided in the Company's Surrebuttal Testimony, as I requested. DOC Ex. ___ at 15 (Campbell Direct) and NSP Ex. ___ at 11 (O'Connor Rebuttal).

Q. Did the Company include examples of nuclear LCM and EPU projects that other companies have undertaken, including the ratio of final to initial costs?

A. Yes. Mr. O'Connor provided in his Table 3 what I expect are selected nuclear projects that had cost overruns. NSP Ex. ___ at 38 (O'Connor Rebuttal).

Q. What do you note based on your review of Table 3?

A. I note that some of the cost overruns for three of the plants were relatively modest and had initial-to-final cost ratios of 1.22, 1.33 and 1.35, reflecting cost overruns of 22% to 35%. I note that another four plants had initial-to-final cost ratios of 1.6 to 1.7, reflecting cost overruns of 60% to 70%. Finally, I noticed that the two highest cost projects in his Table 3 were the Turkey Point/St. Lucie at a 2.2 ratio or a cost-overrun of 120%. By comparison, according to Table 3, Monticello was at a 2.1 ratio indicating a 110% cost overrun. Updating Monticello to reflect the AFUDC costs as of March, 2014 for a total cost of $748.1 million moves that ratio to 2.16 or a cost overrun of 116%. NSP Ex. ___ at 38 (O'Connor Rebuttal).

Q. Are you concerned that Monticello appears to be tied with the Florida nuclear projects (Turkey Point and St. Lucie) for the highest cost nuclear plant (LCM and EPU projects) in the nation?

A. Yes, I am very concerned, especially in light of all the problems and concerns the Department identified in our review of Monticello which have certainly contributed to the unnecessary higher cost of Monticello LCM and EPU projects. Overall, Table 3 and the Department's analysis all confirm that Xcel should have done better; there is no bragging right in being tied with the worst cost overruns.

Q. Mr. Stall noted that the Florida Public Service Commission approved full cost recovery of the 120% cost overrun for Turkey Point; do you think that means the Commission should grant full recovery on the Monticello LCM and EPU projects 116% cost overrun?

A. No. The Commission should base rate recovery of Monticello LCM and EPU projects based on the facts in this and other related Minnesota proceedings.

VII. LACK OF COMMUNICATION BY THE COMPANY REGARDING THE COST OVERRUN WITH THE COMMISSION AND INTERESTED PARTIES

Q. Does Mr. Sparby agree with your statement that the Company did not communicate adequately with the Commission, Department and Interest Parties about the higher costs of the Monticello LCM and EPU projects and especially the increased costs for the EPU?

A. He stated that in some respects the criticism is fair, but in some respects it is a bit unfair. He stated that the Company's "cost increases and Program implementation difficulties were not an unknown fact between 2011 and the present." Xcel Ex. ___ at 29-30 (Sparby Rebuttal). He indicated that the Company's 2011 rate case (Docket No. E002/GR-10-971) "prominently featured discussion of this point, even affecting the procedural schedule after the evidentiary proceeding." He indicated that the Company provided additional rate case updates in 2012 and 2013 and committed to the current prudency review in the 2012 rate case. He stated that "we thought that made it clear that we intended to be transparent about the costs and difficulties we were facing." *Id*. at 30. Finally, he stated his belief that the communication concern by the Department does not impact whether the costs were appropriate or should result in a material asset impairment. *Id*.

Q. Does Mr. Alders also address this communication concern raised by the Department?

A. Yes. First, Mr. Alders noted that the Company did comply with the rules regarding changed circumstances in a CN, and references his Schedule 1. He also noted that in late 2011, the Company filed a Notice of Change Circumstances with the focus of this filing being the delay in implementing the Monticello LCM and EPU projects until the 2013 outage. Second, he noted that the Company provided updates in several Resource Plan proceedings (2004 and 2007 IRPs). Third, Mr. Alders noted that the Company did not provide the cost information in the 2011 Notice of Change Circumstances (NOCC) because they had provided the cost information in the Company's rate cases. Fourth, he stated that the NOCC process "is not designed to address cost increase issues for ongoing projects." Xcel Ex. ___ at 15-17 (Alders Rebuttal).

Q. How do you respond to Mr. Sparby's and Mr. Alders' comments regarding your concern with not communicating higher costs of the Monticello LCM and EPU projects?

A. First, the Company lists the 2010 rate case, 2012 rate case, the 2004 and 2007 CNs and 2011 NOCC where the Company communicated changes about Monticello LCM and EPU projects. However, my communication concern, as correctly noted by Mr. Sparby, focused on the lack of meaningful communication of higher costs of the Monticello LCM and EPU projects (not just general communications), and especially the expected higher costs of the EPU that resulted in the project not being cost effective.[3]

Second, as I noted in my Direct Testimony, it wasn't until the 2010 Rate Case (Docket No. E002/GR-10-971) in the post hearing supplemental testimony of Mr. Kohl on August 25, 2011 on page 7 that the Company indicated the Monticello LCM and EPU costs could exceed $500 million. Since this communication of higher costs didn't take place in the rate case until after the evidentiary hearing and the results reduced Xcel's proposed recovery from ratepayers in that rate case, of course the Department had a very limited opportunity to review these higher Monticello LCM and EPU costs in the 2010 rate case, and we were not that concerned because the net effect was a reduction to rates in the rate case.

Third, the most important and appropriate place would have been for the Company to have provided the higher cost in the NOCC in 2011, since that is when the Company decided the Monticello LCM and EPU projects would be delayed until 2013. Unfortunately, the Company states that it didn't provide its higher costs in the

[3] See DOC Ex. ___ at 6 and 11 (Campbell Direct).

NOCC in 2011 because they had already provided those costs in the rate cases. However, it wasn't until the 2013 rate case that Xcel first requested recovery of the cost overruns and by then Xcel had already mostly spent the money. Given the Company's choices regarding the LCM and EPU projects, it should not be a surprise that it was necessary for the Commission to initiate this special proceeding to assess whether Xcel has met its burden of proof to show as reasonable the amount the Company proposes for ratepayers to pay.

VIII. PRUDENCY CONCERNS AND FORENSIC ACCOUNTING ANALYSIS

Q. What concern does Mr. Sparby raise about the Department's prudency adjustment recommendation?

A. Mr. Sparby stated that although the Department Consultants' Direct Testimony discussed cost increases and was critical of Xcel's performance in certain respects, they do not draw any conclusions whether such cost increases were ultimately necessary or appropriate. As such, he stated that the Consultants did not directly tie any particular action or decision by the Company to a measure of damages. NSP Ex. ___ at 6 (Sparby Direct).

Q. What other concern has Mr. Sparby raised regarding the Department's recommended adjustment for Monticello EPU?

A. Mr. Sparby noted that a cap of costs or of the return on these costs based on Certificate of Need-level information would represent a fundamental shift in the regulatory framework that has guided traditional prudence review under the prudent investment standard. NSP Ex. ___ at 6 (Sparby Rebuttal).

Q. How do you respond to Mr. Sparby's comments regarding lack of support for the Department's prudency adjustment?

A. First, Xcel bears the burden of demonstrating that the costs it incurred and seeks to recover from ratepayers is reasonable. Based on the entirety of the Department's analysis, the Department concludes that Xcel failed to do so. Thus, the Department certainly could have recommended that the Commission deny any recovery of the costs of the overruns, or any rate of return (either on equity or overall). The fact that the Department explored an alternative to Xcel receiving no recovery of Monticello cost overruns is just that, and alternative to Xcel receiving no recovery.

Second, I note that the Department has provided in our Direct and Surrebuttal Testimonies many reasons for the basis of our conclusion that Xcel did not show recovery of the cost overruns to be reasonable, including:

- lack of upfront planning as addressed by Mr. Crisp;
- effects of the "fast-track" approach as addressed by Mr. Crisp;
- inadequate understanding of the true scope of work as addressed by Mr. Jacobs;
- insufficient oversight of contractors and the entire process as addressed by Mr. Crisp;
- start and stop process of contractors addressed by Mr. Crisp;
- poor project management as addressed by Mr. Crisp;
- ineffective use of contingencies as addressed by Mr. Crisp;
- lack of cost controls and tracking concerns as addressed by Ms. Campbell;
- human performance errors raised by NRC as addressed by Ms. Campbell;

- low cost estimates and inadequate information in initial CNs and in this case regarding necessary capital costs as addressed by Ms. Campbell and Mr. Shaw;
- lack of communication by Xcel with Commission and interested parties regarding cost overruns as addressed by Ms. Campbell;
- lack of showing that it is reasonable to allow recovery from ratepayers of the amount of EPU project that is not cost effective as addressed by Mr. Shaw.

Q. Is it feasible to show, item-by-item, how Xcel's decisions increased the costs of the LCM and EPU from the levels that Xcel represented to the Commission in prior proceedings?

A. No, for several reasons. First, general errors such an inadequate planning affect numerous items, not just one. Second, Xcel's accounting for the costs is highly problematic, as discussed above. Third, even if Xcel had tracked costs and information appropriately, even forensic accounting will never uncover an invoice stating that, due to insufficient oversight of contractors, lack of planning, human performance errors, etc. an extra $10 million was incurred, for example. The Department did however, identify several problem areas and gave examples where the Company's actions, which Xcel did not show to be reasonable, clearly lead to higher costs resulting in the Company's 116% cost overrun for the Monticello LCM and EPU projects.

Q. Mr. Sparby claims that a cap or no return on costs based on certificate of need amounts is inconsistent with past precedent; do you agree?

A. No. On pages 22 to 27 of my Direct Testimony, I provided in detail several cases that resulted in caps of costs, no return above the CN estimated amount, or denial of unsupported costs related to generation. So, Xcel has not demonstrated that the Department's proposed partial cost recovery by way of a cap or no return is either unreasonable, outside of Commission authority or would be a change in past precedent. Mr. Sparby also failed to acknowledge that this Monticello case is unique, due to the extent of cost overruns and the lack of transparency regarding the Company's decisions to continue with the projects despite their greatly escalating costs.

Q. What concerns did Mr. Lindell raise about the Department's recommendation for a cost disallowance and the prudency review performed?

A. Mr. Lindell raised the following concerns:

- First, that the Department's recommendation for cost disallowance was not based on whether costs were prudent or reasonable but on a comparative cost allocation analysis.
- Second, that the Department did not conduct any analysis or investigation on whether the cost overruns were prudent or reasonable.
- Third, Department's recommendation to disallow cost overruns that are not cost effective compared to other alternatives is not a prudency review and limits the ability of consumers to enjoy the benefits of "a properly management Monticello project." AUD-OAG Ex. ___ at 5-9 (Lindell Rebuttal).

Q. How do you respond to Mr. Lindell's concerns?

A. First, I understand some of Mr. Lindell's' concerns and agree that the burden of proof is on Xcel to show why the Company should be allowed to recover costs above the levels indicated in the Company's CN proceedings. However, as I discussed in my direct testimony, the Department is taking a balanced approach to help ensure that Xcel is able to operate Monticello in a safe, effective manner.

Second, as discussed above it is not feasible to conduct, item-by-item, the exact dollar measurement for cost overruns pertaining to specific decisions by the Company regarding the LCM and EPU. Instead, the Department identified several problem areas and gave examples that showed the Company's actions clearly lead to higher costs resulting in the Company's 116% cost overrun for the Monticello LCM and EPU projects.

Third, his statement that the Department did not conduct any analysis or investigation on whether the cost overruns were prudent or reasonable is not supported. The testimony of Department witnesses Dr. Jacobs, Mr. Crisp, Mr. Shaw and myself, collectively, show that based on information Xcel knew or reasonably should have known at the time of its decisions, Xcel did not demonstrate that its actions and decisions with respect to the Monticello projects were reasonable. This fact means, of course, that Xcel did not show that its costs were prudently incurred. Moreover, the Department and Department's consultants issued over 100 information requests, did a site visit, did invoice testing, and evaluated the Company's model used in the 2007 IRP and 2008 CN process to determine if the Company showed that its decisions were prudent and cost-effective. So I respectfully disagree with Mr. Lindell's statement.

I also don't agree that no return on cost overrun amounts, caps on cost recovery, comparison to other projects to determine reasonable costs, or disallowance based on not being cost effective, are not reasonable recommendations and adjustments when there are problems with prudency of costs that are not easily measured. In fact, the Commission has approved no return on cost overrun for Nobles Wind, capped cost recovery in riders, and made reductions in costs in Whispering Willow – East based on market price comparison of other wind projects. I noted that I have discussed these cases in detail in my Direct Testimony on pages 22 to 27. DOC Ex. ___ at 22-27 (Campbell Direct).

Q. Mr. Lindell compared the Nobles Wind Farm with the Monticello LCM and EPU projects, and concluded that the Department's proposal in this case deviates significantly from the Nobles Wind Farm case. How do you respond?

A. I note that the facts of these two cases are different. Nobles Wind Farm was a competitively bid project, so the Department concluded that any costs over the bid amount should not be recovered from ratepayers. The ALJ did agree with the Department in this argument; however, the Commission instead approved a disallowance based on no return on the amount over the competitive bid. AUD-OAG Ex. ___ at 9-10 (Lindell Rebuttal).

Q. Mr. Lindell noted that you are not a nuclear engineer and have no experience working with the nuclear industry. How do you respond?

A. I agree that I am not a nuclear engineer, nor have I ever suggested that I am. However, I have worked in energy regulation for 25 years, with over eight years with the Federal Energy Regulatory Commission and close to 17 years with the Department. My working experience in energy regulation has included auditing of nuclear plant capital costs, auditing of operating and maintenance costs, and review of nuclear depreciation and decommission studies. AUD-OAG Ex. ___ at 10-11 (Lindell Rebuttal).

Q. Mr. Lindell stated that in the event that the Commission believes more analysis is required to determine which additional cost overruns were caused by NSP's poor management; he would recommend a forensic accounting analysis, as discussed by Mr. Crisp. How do you respond?

A. First, I note that neither Mr. Crisp nor other Department witnesses recommended a forensic accounting analysis in their Direct Testimony.

Second, given my discussion above regarding the difficulty of finding an invoice showing how much a poor decision increased a particular cost, I do not believe such as approach would be helpful in this case. As a result, I cannot conclude that it would be a reasonable use of resources to pursue such an investigation, since I believe the Department has already provided a well-supported record for our recommended adjustments. Moreover, I note that Mr. Lindell's recommendation is also in the record.

IX. REASONABLENESS OF DEPARTMENT'S RECOMMENDATIONS

Q. What were the recommendations in your Direct Testimony, based on the Department's review of the Monticello LCM and EPU projects?

A. The following were the recommendations in my Direct Testimony based on the Department's review of the Monticello LCM and EPU projects:

- The Monticello plant has issues, including the NRC status of degraded cornerstone, along inadequate planning and management for the Monticello LCM and EPU projects.
- The DOC consultants (Mark Crisp and William Jacobs) raised significant issues in their Direct Testimony about inadequate upfront planning and insufficient understanding about the true scope of the work, along with inadequate oversight of contractors that likely resulted in higher costs of Monticello LCM and EPU projects.
- Based on my concerns noted above regarding transparency, I conclude that the Company did not monitor its costs for Monticello LCM and EPU projects approved in the CN compared to actual costs being incurred. I have concerns with inconsistencies in how the Company tracked costs for accounting purposes compared to CN/IRP purposes that did not tie together or make sense. Additionally, I conclude that the Company should have filed a NOCC as soon as they were aware that the Monticello LCM and EPU project costs were expected to be significantly higher than the amount approved by the Commission in the original CNs, with an evaluation as to whether the Monticello LCM and Monticello EPU projects continued to be cost effective.
- Based on my review, I conclude that estimated final costs for Monticello LCM and EPU projects are $748.1 million on a total company basis, using actual information through March 31, 2014 and estimated vendor credits. The $748.1 million on a total company basis is comprised of $635.3 million for CWIP, $28.0 million for RWIP/removal costs, and $84.8 million for AFUDC. DOC Ex. ___ at NAC-8 (Campbell Direct).
- As noted above, the Department has challenged rate recovery of amounts that have exceeded CN approved amounts, competitive bids, and other amount approved by the Commission. However, the Department has limited its recommended adjustment in this proceeding to the amount of the Monticello EPU that is not cost effective.
- The Department recommends that the Commission disallow $71.42 million on a Minnesota jurisdictional basis with AFUDC costs, for the portion of the Monticello EPU that was not cost-effective due to cost overruns, which is approximately a $10.713 million revenue requirement reduction. This disallowance would continue for the remaining life of the plant, stepping down each year due to

- accumulated depreciation. DOC Ex. ___ at NAC-12 (Campbell Direct).
- The Department recommends that this adjustment be made in 2015.

  DOC Ex. ___ at 34-35 (Campbell Direct).

Q. Since providing the estimated $10.713 million revenue requirement reduction for 2015, with ongoing disallowance for the remaining life of the plant which steps down each year due to accumulated depreciation, have you determined a more exact adjustment?

A. Yes. As noted in my Surrebuttal Testimony in the current Xcel rate case the Company provided the detailed calculations for the Department's Monticello prudency adjustment of $10.237 million for 2015 on a Minnesota Jurisdictional basis, as shown on Attachment A, column (e) in the Company's response to Department information request no. 2148. DOC Ex. ___ at 32 (Campbell Surrebuttal in Docket No. E002/GR-13-868).

Q. Does Mr. Sparby agree with the Department's recommendation for a prudency adjustment of $71.42 million reduction to the capital costs of the Monticello EPU resulting in a $10.237 million revenue requirement downward adjustment for 2015 on a Minnesota Jurisdictional basis, and ongoing adjustment for the life of the plant stepped down for accumulated depreciation?

A. No. Mr. Sparby noted that he does not believe it is appropriate for Xcel to have any "material" disallowance of its cost overruns, despite more than doubling the level of costs that Xcel represented for the LCM and EPU. Xcel Ex. ___ at 34 (Sparby

Rebuttal). He offered no alternative disallowance to the level the Department recommends.

Q. Does it make sense that Xcel's ratepayers should bear the entire burden of the cost overruns for the Monticello LCM and EPU?

A. No. Xcel has not shown this proposal to be reasonable.

Q. What justification did Mr. Sparby offer for his conclusion that all of the cost overruns should be paid for by Xcel's ratepayers?

A. Mr. Sparby claims that the Department's approach involved "hindsight" and instead should have focused on whether the Company's decisions were reasonable based on the facts that were known or reasonably knowable at the time of Xcel's decisions. Xcel Ex. ___ at 34-35 and elsewhere (Sparby Rebuttal). DOC Witnesses Mr. Shaw and Mr. Crisp explain in their surrebuttal testimonies that the Department did exactly that analysis. Mr. Sparby also stated that the Department did not consider the Company's contemporaneous good faith estimate of a reasonable LCM/EPU split, but instead applied and after-the-fact hindsight to re-characterize the split. Dr. Jacobs discusses in his surrebuttal testimony how that split needs to reflect how Xcel's decisions affected the actual costs of the LCM and EPU projects differently.

Q. What were Mr. Sparby's concerns with the magnitude of the Department's proposed disallowance?

A. First, he noted that the impact of the Department's proposal was a concern for the financial health of the utility, particularly in light of the current record. He stated that a significant disallowance without specific facts supporting imprudence or harm could send a signal to investors that our nuclear programs do not have strong regulatory support in Minnesota. He stated his concern that the Department's proposal signals a lack of full appreciation for the complexity of these programs, and for the degree of resources necessary to ensure the integrity and safety of nuclear facilities. He also noted that the Department makes no mention of the issues faced by other utilities and the fact that other regulatory, such as the Florida commission, allowed 100 percent recovery of the similar cost increases. NSP Ex. ___ at 33 (Sparby Rebuttal).

Q. According to Mr. Sparby how would a disallowance of the type suggested by the Department impact the Company?

A. Mr. Sparby indicated that a direct disallowance may have a compounding effect on the Company. He noted the Company's past under recovery of Monticello LCM and EPU projects capital costs in past rate cases and in the current case where the Department has recommended a 2015 in-service date instead of a 2014 in-service date for the Monticello EPU because the 71 MW related to the EPU is not yet up and running. He indicated that a straight disallowance would exacerbate the fact that the Company has not been kept whole for rate recovery for Monticello LCM and EPU. Mr. Sparby attached as Schedule 1 to his Rebuttal Testimony, a spreadsheet prepared by the Company's revenue requirement area that provided the Company estimated level of potential under-recovery. NSP Ex. ___ at 33-34 (Sparby Rebuttal).

Q. How do your respond to the concerns raised by Mr. Sparby regarding the Department's disallowance?

A. I have several responses. First, the Department asked Xcel to "provide copies of all reports available to Xcel regarding the effects of the Department's recommendation on the financial health of Xcel." Rather than providing those reports, Xcel merely stated:

> Mr. Sparby's testimony is based on an overall concern that a material disallowance may result in an adverse financial impact on the Company over the long term. In making this statement, Mr. Sparby was not relying on any specific report or investor comment.
>
> Rather, Mr. Sparby was the Chief Financial Officer of Xcel Energy Inc. from 2009-11 and has experience in the types of issues that concern the capital markets. He recognizes that while difficult, the Company could absorb the direct financial impact of a disallowance in the amount recommended by the Department in this proceeding.
> DOC Ex. ___ at NAC-S-5 IR 135 (Campbell Surrebuttal)

Mr. Sparby's response then reiterates the concerns in his rebuttal testimony, which states, essentially, that it would not be fair to hold Xcel accountable to its representations regarding costs of projects.

Q. What other responses do you have to Mr. Sparby's concerns about the Department's recommended disallowance of recovery of a portion of the cost overruns?

A. Regarding his discussion of "under recovery" of Monticello costs in past rate cases, I note that prior to the E002/GR-12-961, no rate recovery was denied to Xcel. Additionally, the fact that the Monticello EPU was not up and running in the last rate case (12-961) and continues not to be up and running in the current rate proceeding (13-868) means that these Monticello costs are not eligible for cost recovery.

Moreover, the Department's adjustment recommended in Direct Testimony in this proceeding recommends denial of rate recovery only for the not cost effective portion (i.e. ratepayers would have better off if the Company built a gas plant) of the Monticello EPU. This recommendation was reasonable, if not generous, considering all of the concerns the Department identified in this case and the fact that the Company seems to be changing its story from what was said in past Commission proceedings compared to what is being said in this proceeding.

Q. Does AUD-OAG witness Lindell agree with your estimated final cost amount of $748.1 million for the Monticello LCM and EPU projects?

A. Yes. On pages 2-3 of his Rebuttal Testimony, Mr. Lindell used the $748.1 million amount to calculate his cost overrun amount. AUD-OAG Ex. ___ at 2-3 (Lindell Rebuttal).

Q. Mr. Lindell calculated that the cost overrun on Monticello LCM and EPU projects is $428.1 million; do you agree with his calculation?

A. Almost; Mr. Lindell used a $320 million for the total of the two CNs initial cost amounts for the LCM and EPU, however, the Company included in CNs an additional amount for the steam dryer which was required for the project, bring the total CNs estimates to $346 million for the Monticello LCM and EPU projects when escalated to current (2014) dollars. As a result, I noted the cost overrun to be slightly lower at $402.1 million, rather than the $428.1 million calculated by Mr. Lindell.

AUD-OAG Ex. ___ at 2-3 (Lindell Rebuttal) and DOC Ex. ___ at 18-19 (Campbell Direct).

X. SUMMARY OF DEPARTMENT AND OTHER PARTY ADJUSTMENTS

Q. What is your understanding of the AUD-OAG recommended adjustment for Monticello LCM and EPU projects?

A. Mr. Lindell indicated that the cost overrun amount is $428.1 million, for which he recommended 75 percent or $321 million cost disallowance and 25% or $107.1 million to receive no return. I note that using a rough estimate, I believe this recommendation amounts to approximately a downward revenue requirement adjustment of $58 million for 2015 and stepping down for accumulated depreciation over the life of the plant. AUD-OAG Ex. ___ 29-30 (Lindell Rebuttal).

Q. What are other possible adjustments the Commission could consider?

A. I believe the Commission could also consider no return on the $402.1 million cost overrun (as calculated by the Department) which would result in a downward revenue requirement adjustment of $25.796 million for 2015 on a Minnesota Jurisdictional basis (and then stepped down every year due to accumulated depreciation for the life of plant as shown on Attachment A to Department information request no. 127).

Additionally, I believe the Commission could consider allowing Xcel to earn only a weighted short-term and long-term debt return (no equity) of the $402.1 million (consistent with the Department's recommendation in the current rate case for PI EPU that was abandoned). The effect of this adjustment would be a downward revenue requirement adjustment of $20.507 million of 2015 on a Minnesota

Jurisdictional basis (and then stepped down every year due to accumulated depreciation for the life of plant as shown on Attachment B to Department information request no. 127). DOC Ex. ___ at NAC-S-4 (Campbell Surrebuttal).

Q. In response to Department information request no. 127 the Company provided information that indicates they do not agree with the $402.1 million, but instead believe that difference should be $305 million, since AFUDC should not be included. How do you respond?

A. First, I don't believe the Company raised this issue in its Rebuttal Testimony, which would have been a more appropriate place to raise this issue. Second, I don't agree that the AFUDC cost should be excluded. As noted in my Direct Testimony, AFUDC is a cost of the plant in-service amount for which the Company is requesting rate recovery. My understanding is for purposes of CNs/IRPs all cost should be included in the model, including AFUDC costs. Finally, if the Commission denied cost recovery of Monticello LCM and EPU projects, then of course the AFUDC related to those cost must also be denied.

Q. What would be the basis for the Commission to consider either "no return" on the $402.1 million cost overrun or weighted short-term and long-term debt on the $402.1 million?

A. During our review of Monticello LCM and EPU projects, the Department and the Department's consultants found numerous concerns which clearly increased costs and thereby decreased benefits to ratepayers. Additionally, it is extremely concerning that the Monticello EPU additional 71 MW is not up and running yet, likely won't be until 2015, and at this point I would think the Commission and interested parties would want to see Monticello EPU project up and running soon. The Monticello LCM and EPU were supposed to have been in-service in 2011, then in 2013 (which is when the LCM was put in-service) and then the EPU was supposed to have been in-service in 2014 and is now expected to be in-service in 2015. Having a fully functional plant is an important consideration.

Q. Does the Department continue to recommend the prudency adjustment recommended in your Direct Testimony of $71.42 million reduction to the capital costs of the Monticello EPU resulting in a $10.237 million revenue requirement downward adjustment for 2015 on a Minnesota Jurisdictional basis, and ongoing adjustment for the life of the plant stepped down for accumulated depreciation?

A. Yes. However, I continue to note the Department's concerns listed in my testimony above and ongoing concerns with Monticello EPU not being up and running. I note that this record could also support higher disallowances, even though the Department is not making such a recommendation at this time.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

Docket No. E002/CI-13-754
DOC Ex. ___ NAC-S-1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE RD. SUITE 210
LISLE, IL 60532-4352

September 2, 2014

Ms. Karen Fili
Site Vice President
Monticello Nuclear Generating Plant
Northern States Power Company, Minnesota
2807 West County Road 75
Monticello, MN 55362–9637

SUBJECT: MID-CYCLE ASSESSMENT LETTER FOR MONTICELLO NUCLEAR GENERATING PLANT

Dear Ms. Fili:

On August 6, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed its mid-cycle performance review of Monticello Nuclear Generating Plant. The NRC reviewed the most recent quarterly performance indicators (PIs) in addition to inspection results and enforcement actions from July 1, 2013 through June 30, 2014. This letter informs you of the NRC's assessment of your facility during this period and its plans for future inspections at your facility.

The NRC determined the performance at Monticello Nuclear Generating Plant during the most recent quarter was within the Degraded Cornerstone Column of the NRC's Reactor Oversight Process (ROP) Action Matrix because of one Yellow finding, with substantial safety significance, in the Mitigating Systems Cornerstone. The finding involved the failure to maintain a procedure addressing all of the effects of an external flooding scenario on the plant

As described in our Assessment Followup-Letter issued on August 28, 2013 (ADAMS Accession No. ML 13240A435), Monticello Nuclear Generating Plant transitioned from the Licensee Response column to the Degraded Cornerstone Column of the ROP Action Matrix in the second quarter of 2013 due to the Yellow finding related to the failure to maintain a procedure addressing all of the effects of an external flooding scenario on the plant. This failure resulted in the site not being able to support the timely implementation of flood protection activities within the 12-day timeframe credited in the design basis as stated in the updated safety analysis report. This finding will remain open until the successful completion of Inspection Procedure 95002, "Supplemental Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area."

On July 18, 2014, your staff notified the NRC of your readiness for it to conduct a supplemental inspection to review the actions taken to address the performance issues. Therefore, in addition to ROP baseline inspections, the NRC plans to conduct a supplemental inspection in accordance with Inspection Procedure 95002, "Supplemental Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area," to review the actions taken to address the performance issues. The NRC has not yet scheduled this inspection.

The NRC identifies substantive cross-cutting issues (SCCIs) to communicate a concern with the licensee's performance in a cross-cutting area and to encourage the licensee to take appropriate actions before more significant performance issues emerge. The NRC identified a cross-cutting theme in the Human Performance, Conservative Bias aspect (H.14). Specifically, five inspection findings for the current 12-month assessment period were a cross-cutting aspect of H.14, "Individuals use decision-making practices that emphasize prudent choices over those that are simply allowable." The NRC determined that an SCCI exists because the NRC has a concern with your staff's scope of effort and progress addressing the cross-cutting theme associated with Human Performance, Conservative Bias (H.14). Specifically, the NRC noted that your staff missed an early opportunity to identify this SCCI and, therefore failed to recognize that the SCCI affected overall plant performance. As a result, corrective actions to address the SCCI were unnecessarily delayed resulting in continued, declining performance in this area.

In October 2013, after an adverse trend was identified in your corrective action program for three NRC-identified issues associated with this cross-cutting aspect, your staff determined that an apparent cause evaluation was necessary to address this issue. The apparent cause evaluation was subsequently cancelled and justifications were determined to be incorrect and delayed full understanding of the significance of the lack of conservative bias in decision making until April 2014, after another three NRC-identified findings with related H.14 aspects had been identified during the first quarter 2014. In total, six NRC-identified findings with H.14 aspects had been identified between February 2013 and April 2014. In May 2014, your staff completed a root cause evaluation which concluded that these issues reflected current organizational behavior and resulted from inadequate decision making and delayed corrective action from prior, similar issues. In particular, the root cause evaluation noted that the failure to take corrective actions in October 2013 was a result of underlying organizational behaviors. Given these circumstances and the recency of your additional actions, we cannot conclude that the corrective actions will be fully effective in addressing the cross-cutting theme.

This human performance SCCI will remain open until the number of findings with a cross-cutting aspect of H.14 is reduced, the corrective actions taken to mitigate the cross-cutting theme prove effective, and sustained performance improvement is observed in the H.14 aspect of the human performance area. The NRC will monitor your staff's effort and progress in addressing the SCCI by evaluating your corrective action program, any root cause evaluations for the SCCI, and performance improvement initiatives.

In its assessment letter dated March 4, 2014 (ML14063A307), the NRC opened an SCCI in human performance with the aspect of H.7, "the organization creates and maintains complete, accurate and up-to-date documentation" (formally referred to as H.2(c)). As stated in the letter, this SCCI will remain open until the number of findings with a cross-cutting theme in H.7 is reduced, the corrective actions taken to mitigate the cross-cutting theme prove effective, and sustained performance improvement is observed in the H.7 aspect of the human performance area.

To address the SCCI in H.7, your staff performed an apparent cause evaluation in July 2013 and a root cause evaluation in February 2014. These evaluations identified weaknesses in site leadership not enforcing quality work documents for procedures that are being approved for use in the plant. In response, your staff developed performance improvement plans for each department, improved supervisory field oversight, and implemented additional training for supervisors. The NRC noted that that the number of findings with a cross-cutting aspect of H.7 remains above the threshold for assigning a cross-cutting aspect and that those corrective actions taken have not yet proven effective in substantially mitigating the cross-cutting theme even though a reasonable duration of time has passed. Therefore, this SCCI will remain open until the closure criteria stated above are met. Because this letter is the second consecutive assessment letter documenting an SCCI with the same cross-cutting aspect, the NRC requests your staff to provide a written response documenting your planned actions to address this SCCI. The NRC will continue to monitor your staff's effort and progress in addressing the SCCI by evaluating your corrective action program, any evaluations for the SCCI, and performance improvement initiatives.

As a result of the Safety Culture Common Language Initiative, the terminology and coding of cross-cutting aspects were revised. All cross-cutting aspects identified during inspections conducted in calendar year 2014 reflect this revision to Inspection Manual Chapter (IMC) 0310. Cross-cutting aspects identified in 2013 using the 2013 terminology were converted to the latest revision in accordance with the cross-reference in IMC 0310 during the mid-cycle assessment review and evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with IMC 0305.

The enclosed inspection plan lists the inspections scheduled through December 31, 2015. Routine inspections performed by resident inspectors are not included in the inspection plan. The inspections listed during the last 9-months of the inspection plan are tentative and may be revised at the end-of-cycle performance review. The NRC provides the inspection plan to allow for the resolution of any scheduling conflicts and personnel availability issues. The NRC will contact you as soon as possible to discuss changes to the inspection plan should circumstances warrant any changes. This inspection plan does not include security related inspections, which will be sent via separate, non-publicly available correspondence.

In response to the accident at Fukushima, the Commission issued Order EA-12-049, "Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events," which requires licensees to develop, implement, and maintain guidance and strategies to maintain or restore core cooling, containment, and spent fuel pool cooling capabilities following a beyond-design-basis external event. Additionally, the Commission issued Order EA-12-051, "Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation," which requires licensees to have a reliable means of remotely monitoring wide-range Spent Fuel Pool levels to support effective prioritization of event mitigation and recovery actions in the event of a beyond-design-basis external event. The NRC is conducting audits of licensee efforts towards compliance with these Orders. This audit includes an onsite component in order for the NRC to evaluate licensee plans for complying with the Orders, as described in site-specific submittals, and to receive and review information relative to associated open items. This onsite activity will occur in the months prior to a declaration of compliance for the first unit at each site, and will aid staff in development of an ultimate Safety Evaluation for the site. The date for the onsite component at your site is being coordinated with your staff. A site-specific audit plan for the visit will be provided in advance to allow sufficient time for preparations.

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Please contact Kenneth Riemer at 630–829–9628 with any questions you have regarding this letter.

Sincerely,

/RA/

Cynthia D. Pederson
Regional Administrator

Docket Nos. 50–263
License Nos. DPR–22

Enclosure:
Monticello Nuclear Generating Plant
Inspection/Activity Plan

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Please contact Kenneth Riemer at 630–829–9628 with any questions you have regarding this letter.

Sincerely,

/RA/

Cynthia D. Pederson
Regional Administrator

Docket Nos. 50–263
License Nos. DPR–22

Enclosure:
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Inspection/Activity Plan

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Monticello
Inspection / Activity Plan
09/01/2014 - 12/31/2015

Unit Number	Planned Dates Start	End	Inspection Activity		Title	No. of Staff on Site
			ISFSI	**- PROGRAM REVIEW**		**2**
1	09/01/2014	10/31/2014	IP 60855.1		Operation of an Independent Spent Fuel Storage Installation at Operating Plants	
			PI&R	**- BIENNIAL PI&R INSPECTION**		**4**
1	09/22/2014	10/10/2014	IP 71152B		Problem Identification and Resolution	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**		**1**
1	12/01/2014	12/06/2014	IP 71124.08		Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**		**2**
1	12/15/2014	12/19/2014	IP 71124.02		Occupational ALARA Planning and Controls	
1	12/15/2014	12/19/2014	IP 71124.06		Radioactive Gaseous and Liquid Effluent Treatment	
1	12/15/2014	12/19/2014	IP 71151-BI01			
1	12/15/2014	12/19/2014	IP 71151-OR01			
1	12/15/2014	12/19/2014	IP 71151-PR01			
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**		**1**
1	01/12/2015	01/16/2015	IP 71124.03		In-Plant Airborne Radioactivity Control and Mitigation	
1	01/12/2015	01/16/2015	IP 71124.04		Occupational Dose Assessment	
			BI ISI	**- ISI INSPECTION**		**1**
1	04/11/2015	05/11/2015	IP 7111108G		Inservice Inspection Activities - BWR	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**		**1**
1	04/20/2015	04/24/2015	IP 71124.01		Radiological Hazard Assessment and Exposure Controls	
1	04/20/2015	04/24/2015	IP 71124.02		Occupational ALARA Planning and Controls	
			OL PREP	**- INIT EXAM/JUNE 2015**		**3**
1	05/11/2015	05/15/2015	W90331		OL - INITIAL EXAM - 2015 MAY-JUN - MONTICELLO	
			OL EXAM	**- INIT EXAM/JUNE 2015**		**3**
1	06/01/2015	06/12/2015	W90331		OL - INITIAL EXAM - 2015 MAY-JUN - MONTICELLO	
			BI ENG	**- COMPONENT DESIGN BASIS INSPECTION**		**6**
1	06/22/2015	07/24/2015	IP 7111121		Component Design Bases Inspection	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**		**1**
1	08/10/2015	08/14/2015	IP 71124.07		Radiological Environmental Monitoring Program	
1	08/10/2015	08/14/2015	IP 71151-BI01			
1	08/10/2015	08/14/2015	IP 71151-OR01			
1	08/10/2015	08/14/2015	IP 71151-PR01			
			BL EPR	**- EP ROUTINE INSPECTION / PI VERIFICATION**		**1**
1	08/17/2015	08/21/2015	IP 7111407		Exercise Evaluation - Hostile Action (HA) Event	

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

Monticello
Inspection / Activity Plan
09/01/2014 - 12/31/2015

Unit Number	Planned Dates Start	Planned Dates End	Inspection Activity	Title	No. of Staff on Site
			BL EPX	**- EP EXERCISE / PI VERIFICATON**	2
1	08/17/2015	08/21/2015	IP 7111407	Exercise Evaluation - Hostile Action (HA) Event	
1	08/17/2015	08/21/2015	IP 7111408	Exercise Evaluation – Scenario Review	
1	08/17/2015	08/21/2015	IP 71151	Performance Indicator Verification	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**	1
1	09/28/2015	10/02/2015	IP 71124.02	Occupational ALARA Planning and Controls	
			BI OLRQ	**- BIENNIAL REQUAL PROGRAM INSPECTION**	2
1	10/19/2015	10/23/2015	IP 7111111B	Licensed Operator Requalification Program	

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE RD. SUITE 210
LISLE, IL 60532-4352

September 2, 2014

Mr. Kevin Davison
Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company, Minnesota
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: MID-CYCLE ASSESSMENT LETTER FOR PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2

Dear Mr. Davison:

On August 6, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed its mid-cycle performance review of Prairie Island Nuclear Generating Plant, Units 1 and 2. The NRC reviewed the most recent quarterly performance indicators (PIs) in addition to inspection results and enforcement actions from July 1, 2013 through June 30, 2014. This letter informs you of the NRC's assessment of your facility during this period and its plans for future inspections at your facility.

The NRC determined that overall, Prairie Island Nuclear Generating Plant, Unit 1 operated in a manner that preserved public health and safety and met all cornerstone objectives. The NRC determined the performance at Prairie Island Nuclear Generating Plant, Unit 1 during the most recent quarter was within the Licensee Response Column of the NRC's Reactor Oversight Process (ROP) Action Matrix because all inspection findings had very low (i.e., green) safety significance, and all PIs indicated that your performance was within the nominal, expected range (i.e., green). Therefore, the NRC plans to conduct ROP baseline inspections at your facility.

The NRC determined the performance at Prairie Island Nuclear Generating Plant, Unit 2 during the most recent quarter was within the Regulatory Response Column of the NRC's ROP Action Matrix because of one low-to-moderate safety significant (White) PI for Emergency Alternating Current Power Systems in the Mitigating Systems Performance Index.

On April 24, 2014, your staff notified the NRC of your readiness for it to conduct a supplemental inspection to review the actions taken to address the performance issues. Therefore, in addition to ROP baseline inspections, the NRC commenced a supplemental inspection in accordance with Inspection Procedure 95001, "Supplemental Inspection for One or Two White Inputs in a Strategic Performance Area," on August 25, 2014. The NRC also plans to conduct Temporary Inspection Procedure 2515–189 "Inspection to Determine Compliance of Dynamic Restraint (Snubber) Program with 10 CFR 50.55a."

"The NRC identifies substantive cross-cutting issues (SCCIs) to communicate a concern with the licensee's performance in a cross-cutting area and to encourage the licensee to take appropriate actions before more significant performance issues emerge. The NRC identified a cross-cutting theme in the Human Performance, Documentation aspect (H.7). Specifically, four inspection findings for the current 12-month assessment period were assigned a cross-cutting aspect of H.7, "the organization creates and maintains complete, accurate and up-to-date documentation." The NRC determined that an SCCI exists because the NRC has a concern with your staff's scope of effort and progress in addressing the cross-cutting theme associated with H.7.

To address the SCCIs, your staff initiated a corrective action document in July 18, 2014, with an assignment to perform an evaluation of the issue by the end of August 2014. Although each specific issue was addressed, there were no interim corrective actions taken to address this trend. The NRC is concerned that the apparent lack of urgency to address this SCCI was symptomatic of the overall weakness in your corrective action program. Specifically, NRC inspections of the corrective action program conducted in 2012 and 2014 (ML12269A253 and ML14218A268) identified numerous challenges to its efficacy, resulting a significant backlog of issues that remained uncorrected. The NRC also noted that minimal corrective actions had been taken to address these challenges between the 2012 and 2014 inspections. Therefore, the NRC was not confident that your staff would effectively address the SCCI prior to the end of the current assessment period, given the lack of any specific interim actions and the overall poor performance of the corrective action program.

This human performance SCCI will remain open until the number of findings with a cross-cutting aspect of H.7 is reduced, the corrective actions taken to mitigate the cross-cutting theme prove effective, and sustained performance improvement is observed in the H.7 aspect of the human performance area. The NRC will monitor your staff's effort and progress in addressing the SCCI by evaluating your corrective action program, any evaluations for the SCCI, and performance improvement initiatives.

As a result of the Safety Culture Common Language Initiative, the terminology and coding of cross-cutting aspects were revised. All cross-cutting aspects identified during inspections conducted in calendar year 2014 reflect this revision to Inspection Manual Chapter (IMC) 0310. Cross-cutting aspects identified in 2013 using the 2013 terminology were converted to the latest revision in accordance with the cross-reference in IMC 0310 during the mid-cycle assessment review and evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with IMC 0305.

The enclosed inspection plan lists the inspections scheduled through December 31, 2015. Routine inspections performed by resident inspectors are not included in the inspection plan. The inspections listed during the last nine months of the inspection plan are tentative and may be revised at the end-of-cycle performance review. The NRC provides the inspection plan to allow for the resolution of any scheduling conflicts and personnel availability issues. The NRC will contact you as soon as possible to discuss changes to the inspection plan should circumstances warrant any changes. This inspection plan does not include security related inspections, which will be sent via separate, non-publicly available correspondence.

In response to the accident at Fukushima, the Commission issued Order EA-12-049, "Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events," which requires licensees to develop, implement, and maintain guidance and strategies to maintain or restore core cooling, containment, and spent fuel pool cooling capabilities following a beyond-design-basis external event. Additionally, the Commission issued Order EA-12-051, "Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation," which requires licensees to have a reliable means of remotely monitoring wide-range Spent Fuel Pool levels to support effective prioritization of event mitigation and recovery actions in the event of a beyond-design-basis external event. The NRC is conducting audits of licensee efforts towards compliance with these Orders. This audit includes an onsite component in order for the NRC to evaluate licensee plans for complying with the Orders, as described in site-specific submittals, and to receive and review information relative to associated open items. This onsite activity will occur in the months prior to a declaration of compliance for the first unit at each site, and will aid staff in development of an ultimate Safety Evaluation for the site. The date for the onsite component at your site is being coordinated with your staff. A site-specific audit plan for the visit will be provided in advance to allow sufficient time for preparations.

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Please contact Kenneth Riemer at 630–829–9628 with any questions you have regarding this letter.

Sincerely,

/RA/

Anne T. Boland, Division Director
Division of Reactor Projects

Docket Nos. 50–282, 50–306 and 72–010
License Nos. DPR–42, DPR–60 and SNM–2506

Enclosure:
Prairie Island Nuclear Generating Plant
Inspection/Activity Plan

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maintain guidance and strategies to maintain or restore core cooling, containment, and spent fuel pool cooling capabilities following a beyond-design-basis external event. Additionally, the Commission issued Order EA-12-051, "Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation," which requires licensees to have a reliable means of remotely monitoring wide-range Spent Fuel Pool levels to support effective prioritization of event mitigation and recovery actions in the event of a beyond-design-basis external event. The NRC is conducting audits of licensee efforts towards compliance with these Orders. This audit includes an onsite component in order for the NRC to evaluate licensee plans for complying with the Orders, as described in site-specific submittals, and to receive and review information relative to associated open items. This onsite activity will occur in the months prior to a declaration of compliance for the first unit at each site, and will aid staff in development of an ultimate Safety Evaluation for the site. The date for the onsite component at your site is being coordinated with your staff. A site-specific audit plan for the visit will be provided in advance to allow sufficient time for preparations.

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Division of Reactor Projects

Docket Nos. 50–282, 50–306 and 72–010
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Letter to Kevin Davison from Anne Boland dated September 2, 2014.

SUBJECT: MID-CYCLE ASSESSMENT LETTER FOR PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2

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Prairie Island
Inspection / Activity Plan
09/01/2014 - 12/31/2015

Unit Number	Planned Dates Start	Planned Dates End	Inspection Activity	Title	No. of Staff on Site
			BI ISI	**- INSERVICE INSPECTION UNIT 1 & SNUBBER TI**	**2**
1, 2	10/08/2014	11/22/2014	IP 2515/189	Inspection to Determine Compliance of Dynamic Restraint (Snubber) Program with 10 CFR 50.55a	
2	10/08/2014	11/22/2014	IP 7111108P	Inservice Inspection Activities - PWR	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**	**1**
1	11/03/2014	11/07/2014	IP 71124.01	Radiological Hazard Assessment and Exposure Controls	
			ISFSI	**- ISFSI OPERATION AT A SITE INSPECTION**	**2**
1	04/01/2015	05/31/2015	IP 60855.1	Operation of an Independent Spent Fuel Storage Installation at Operating Plants	
			BI ISI	**- ISI UNIT 2 INSPECTION**	**1**
2	09/18/2015	10/23/2015	IP 7111108P	Inservice Inspection Activities - PWR	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**	**1**
1	04/13/2015	04/17/2015	IP 71124.01	Radiological Hazard Assessment and Exposure Controls	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**	**1**
1	05/18/2015	05/22/2015	IP 71124.06	Radioactive Gaseous and Liquid Effluent Treatment	
			BI EPR	**- EP ROUTINE INSPECTION / PI VERIFICATION**	**2**
1	07/13/2015	07/17/2015	IP 7111402	Alert and Notification System Testing	
1	07/13/2015	07/17/2015	IP 7111403	Emergency Preparedness Organization Staffing and Augmentation System	
1	07/13/2015	07/17/2015	IP 7111405	Correction of Emergency Preparedness Weaknesses and Deficiencies	
1	07/13/2015	07/17/2015	IP 71151	Performance Indicator Verification	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**	**1**
1	07/13/2015	07/17/2015	IP 71124.07	Radiological Environmental Monitoring Program	
1	07/13/2015	07/17/2015	IP 71151-BI01		
1	07/13/2015	07/17/2015	IP 71151-OR01		
1	07/13/2015	07/17/2015	IP 71151-PR01		
			BI ENG	**- COMPONENT DESIGN BASIS INSPECTION**	**6**
1, 2	08/03/2015	09/04/2015	IP 7111121	Component Design Bases Inspection	
			BI OLRQ	**- BIENNIAL REQUAL PROGRAM INSPECTION**	**2**
1, 2	09/21/2015	09/25/2015	IP 7111111B	Licensed Operator Requalification Program	
			BI RP	**- RADIATION PROTECTION BASELINE INSPECTION**	**1**
1	10/26/2015	10/30/2015	IP 71124.02	Occupational ALARA Planning and Controls	

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

Q. According to Ms. Perkett, was the plant addition of $167.4 million for Monticello LCM/EPU placed in service in January 2014 reflected in the 2014 revenue requirements?

A. Ms. Perkett provided the following response on page 22 of her Direct Testimony:

> Yes. This change was not included in the 2014 budget and, therefore, Ms. Heuer, in her Direct Testimony, includes an adjustment to reflect this change to the 2014 test year revenue requirement. A schedule showing the total Company calculation is provided as Exhibit___(LHP-1), Schedule 5.
> NSP Ex. ___ at 22 (Perkett Direct).

Q. In the above questions and answers the Company estimated in-service date of January 2014; however, is the Monticello LCM/EPU project operating at its full 671 MW level (specifically the 71 MW related to the EPU) at this time?

A. No. As a result, the Department asked Xcel in the Monticello CI docket to identify the steps that are necessary before Monticello operates at its full 671 MW level and to indicate the expected dates for each step. The Company provided the following response to DOC information request no. 115 in Docket No. E002/CI-13-754:

> Monticello has specific license requirements that must be met and verified during power ascension testing. The testing will take the station from its previous licensed output of 1775 MWt (approximately 609 MWe) to our new approved output of 2004 MWt (approximately 671 MWe).
>
> The process is such that the Company increases power in small increments and collects data for verification against licensed parameters. When the station reaches predefined power levels the data is collected and sent to the NRC for review. The station will not move up in power without NRC concurrence. NRC review times vary based on the data being evaluated and how close it correlates to the values submitted during the licensing process.

Testing to Date:
After receiving the EPU license on December 9, 2013, the Company began its ascension plan. Power was increased in December and testing began. We moved through the first two power ascension set points in December and January. Then on March 11, 2014, the unit reached the first required data collection plateau, which was 1864 MWt (approximately 640 MWe). The data collection is required as part of the Power Uprate License and is intended to provide verification that the steam dryer is not reasonably likely to be damaged as a result of uprated conditions as occurred at Quad Cities. The data was collected and sent to the vendor for review and their concurrence. During that review, the vendor discovered that the stresses were running lower than expected, consistently across the entire data collection range, by a factor of 2. As a result, to comply with our license, we returned the plant to the previously known safe power level of 1775MWt (approximately 609 MWe).

The vendor reviewed the data and determined that a programming error was made during the initial setup for data collection. The program was initially changed to accommodate reactor vessel pressure testing, which is required by technical specifications to restart the reactor, but was not reset properly to capture steam loads; thus, creating the error. This data anomaly was easily reconciled and the offset was dispositioned by the vendor. However, as part of the normal process of conducting additional extent of condition review of the entire data provided, we discovered a configuration issue associated with the wiring to the strain gauges on one of the main steam lines (located in the Drywell). The upper and lower wires were mislabeled and thus lead us to connect them incorrectly at the data Collection Panel located outside of the Drywell. The physical distances are different between the upper and lower collection points and this requires the vendor to re-run their stress model with the correct configurations. Following the completion of their data set runs, Xcel Energy will review the results and submit them to the NRC as required by the license. Once the NRC completes their review we will resume power ascension testing.

Steps Going Forward:
We expect our reanalysis and re-verification of the model and the inputs and outputs to be completed by the end

of June and we expect NRC review will take approximately one month, so we expect to re-enter power ascension in August, assuming no additional licensing activities are required. The Company believes that we will be able to achieve full power of 2004 MWt (approximately 671 MWe) by the end of 2014 based on the following ascension plan, which contains the same steps as our pre-data issue plan but with different dates:

- August- Raise power to 1819 MWt (approximately 624 MWe) for Steam Dryer Data only.
- Early September- Raise power to 1864 MWt (105% or approximately 640 MWe) for Steam Dryer only (This is the power level that we need to submit Dryer Data to NRC)
    - Submit the data to the NRC for their review and concurrence.
- Late September- Raise Power to 1908 MWt (approximately 658 MWe) and commence Dynamic Testing.
- October- Transition to M+ Operating Domain, as required by the license. This transition will result in a power reduction to 1686 MWt (approximately 580 MWe), which is the starting verification point on the operators Power to Flow Map.
- October- Raise power to M+ 1775 MWt (approximately 609 MWe)
- Mid-November- Raise power to M+ 1864 MWt (105% or approximately 640 MWe)
- Mid-November- Raise power to M+ 1908 MWt (approximately 658 MWe).
- End of November- Raise Power to EPU 1953 MWt (approximately 664 MWe)
    - Submit the data to the NRC for their review and concurrence.
- December- Raise Power to EPU 2004 MWt (approximately 671 MWe) output. The 2004 MWt power level correlates to the new power level of 671MWe and will end the testing window pending NRC concurrence. The time line provided is based on timely reviews by the vendors and the NRC. Should the data render unexpected results, the review times could be impacted.

  DOC Ex. ___ at NAC-8 (Campbell Direct).

Q. **What does this response mean as to when the Company now believes the EPU will be in service?**

A. The Company's response above means that the Company is now estimating that the plant will be operating at 640 MW in August 2014, meaning 40 MW of the EPU will be in service by that time. Then, in December 2014 the Company estimates that the full Monticello EPU with approximately 671 MW will be available to serve ratepayers.

Q. **Does the Company's response suggest there may be uncertainties in this timeline?**

A. Yes, there are a number of assumptions in the Company's response that may or may not actually happen in the manner or estimated timeline that could affect how much of the EPU is available to serve customers at which times. Of course, safety and compliance with NRC standards are important factors. Thus, it is hoped that 40 MW will be available by the time of the evidentiary hearing in this matter and that the remaining 31 MW would be available by the end of 2014, but those dates are not guaranteed at this time.

Q. **Do you have concerns about this delay regarding the remaining life of the Monticello LCM/EPU project for ratemaking purposes?**

A. Yes. For non-nuclear generation plants the in-service date is determined and the useful life of 20 or 30 years (whatever is appropriate) then begins, so delays of in-service won't likely shorten the life of the plant. However, the lives of nuclear generation plants are tied to an NRC operational license of 20 years. So delays of getting the EPU portion of the Monticello plant up and running are shortening the useful life of the EPU since the remaining life of the NRC license was at 16.8 years as of January 1, 2014, as shown in the Company's 2014 remaining life depreciation study dated February 28, 2014 in Docket No. G,E002/D-14-181, Attachment A page 3 of 9, DOC Ex. ___ at NAC-9 (Campbell Direct).

What that means for ratemaking purposes is that, if the in-service on the Monticello EPU doesn't happen until January 2015, then the remaining useful life (due to NRC license) will be reduced to only 15.8 years that this plant will be able to serve ratepayers.

Q. Although the Department will be discussing the total costs of Monticello LCM/EPU in the Monticello CI docket, is there any preliminary information about the expected final cost of the Monticello LCM/EPU?

A. Yes. In response to DOC information request no. 88 Attachment A in Docket No. E002/CI-13-754, the Company provided its expected final cost of the Monticello LCM/EPU project (actual costs through March 31, 2014 and remaining forecasted cost and vendor credits) as follows:

• Construction Work in Progress (CWIP) only	$635,340,310
• Allowance for Funds Used During Construction (AFUDC)	$ 84,751,230
• Retirement Work In Progress (Removal Costs/RWIP)	$ 28,039,015
Total Costs of Monticello LCM/EPU	$748,130,555

DOC Ex. ___ at NAC-10 (Campbell Direct).

Q. Is there preliminary information about the costs Xcel estimated in their petitions for certificates of need?

A. Yes. In response to DOC information request no. 94 in Docket No. E002/CI-13-754, the Company provided the following information (as summarized by the Department) regarding its CN estimated for Monticello LCM/EPU Docket No. E002/CN-08-185:

- Monticello LCM was estimated at $135 million (in 2004 $);
- Monticello EPU was estimated at $104, which increases $29 million to $133 million (in 2004 $) when the steam generator is included;
- Monticello LCM/EPU total estimated cost is $320 to $346 million when escalated to current (2014) dollars. DOC Ex. ___ at NAC-11 (Campbell Direct).

Q. While the Department will address these issues further in the concurrent investigation proceeding, what do you note at this time about the costs, in response to Mr. O'Connor's testimony about the cost overruns?

A. I note that the final costs of the Monticello LCM/EPU project are more than double the costs of the initial CN estimate, even when inflation is included. More importantly for this rate proceeding, I note that Xcel has indicated that the full amount (71 MW) of the EPU will not be available to serve ratepayers for most if not all of 2014.

Q. Based on your review of the Monticello LCM/EPU projects for the 2014 test year, (subject to further review in the Monticello CI docket) what do you recommend at this time?

A. Since the Monticello EPU project (71 additional MW) will not be available for most if not all of the 2014 test year, it is necessary to adjust Xcel's revenue requirement since their assumption that the EPU would have been in-service as of January 1, 2014 clearly did not occur. Since the EPU is not in place, it is not reasonable for ratepayers to pay for the Monticello EPU in 2014 rates. Thus, for 2014, I recommend that the Commission deny recovery of depreciation expense and return for the 2014 test year for the Monticello EPU project (estimated as 41.6% of the Monticello LCM/EPU project and subject to review in the Monticello CI docket). However, if the EPU is partially in service by the time of the evidentiary hearing, I may be willing to consider amending this adjustment.

Nonetheless, I have concerns about significant costs overruns and the delays that continue to reduce the useful life of the Monticello EPU project, which will likely only be available to ratepayers for 15.8 years (assuming a January 2015 in-service date) instead of 20 years initial planned via the NRC license. These issues will be addressed further in the investigation docket.

As noted earlier, the Department in its Rebuttal Testimony of this rate case will bring forward the Department's recommendations regarding the prudency of Monticello LCM and EPU projects, using the Department's recommendations in our Direct Testimony in Monticello CI docket. Based on this information the Department intends to recommend in our Rebuttal Testimony of this rate case any resulting adjustments for rate recovery for the Monticello LCM & EPU. Additionally, in light of the concerns regarding the Monticello actual in-service date, it may be appropriate to require some compliance filing prior to including the Monticello EPU in 2015 rates, to ensure that the Monticello EPU actual goes in-service.

continue to disagree with Ms. Perkett that the entire plant is ready for use for ratemaking purposes, as is demonstrated by the Company's own testimony. As a fundamental ratemaking principle the EPU has not yet been shown to be used and useful.

Q. How do you respond to Xcel's argument that the fact that the plant is not operating as the Company proposed in its rate case is similar to any other plant outage?

A. I do not agree with Mr. Clark that this very capital-intensive project should be treated like a plant outage. Given that: 1) the NRC has not allowed the plant to operate at the 671 MWe level, 2) the plant is not operating at the 640 MWe level for the reasons discussed above, and 3) the plant *is* operating at 600 MWE, current operations and non-operations of the plant cannot be considered to be a plant outage. Instead, the fact remains that the Monticello EPU has not yet been approved to be fully up and running at the 671 MW level, and may not reach that level for most or all of 2014 based on the Company's response to Department information request 115.

Q. What is your overall conclusion about whether Xcel has shown the Monticello EPU to be used and useful for 2014?

A. My understanding of Minnesota law, Minn. Stat. § 216B.03, is that the benefit of any doubt as to reasonableness must go to the consumer. Thus, for purposes of the 2014 test year, I do not agree that Xcel has shown that it is reasonable to include the Monticello EPU as being in-service based on the Company's hope that it may be approved by the NRC and that it may meet final testing protocols upon the resumption of power ascension testing in order to be fully operational by December 2014 (see response to Department information request 115, NAC-8 of my Direct Testimony). While I remain open to allowing some recovery of the Monticello EPU if the EPU is in service or partially in service by the time of the evidentiary hearing in this proceeding, I note that it is Xcel's responsibility (and burden) to show why ratepayers should pay for costs of the EPU in 2014 (and thereafter).

Q. Do you have any other notes regarding the useful life of the Monticello EPU?

A. Yes. As I noted in on pages 54 and 55 of my Direct Testimony regarding the fact that ratepayers will not receive the full benefit of the NRC license life of 20 years, if the in-service date for the Monticello EPU doesn't occur until January 2015, then the remaining useful life will be reduced to a period of 15.8 years that this plant will be able to serve ratepayers, which is clearly a significant reduction to ratepayers of 21 percent of actual benefits of the EPU uprate of 71 MW.

Q. According to Mr. O'Connor what are the three key changes for the Monticello LCM/EPU that are different from when the Commission issued its order in the last Xcel rate case and did not allow Xcel to recover the costs of the Monticello EPU in rates because it was not used and useful and/or available for customer use?

A. Mr. O'Connor provided the following three key changes:

> Three key items are pertinent to this case and I will discuss each separately. The first relates to the approval status of the license amendments, which are required for the plant to operate at the uprated power level. The second relates to plant status to date and the expected timeframe for our completion of the uprate ascension process to achieve full uprate output levels.

> Finally, I will provide an update to the LCM/EPU split as proposed by the Company in the Prudence Docket.

Xcel Ex. __ at 4 (O'Connor Rebuttal)

Q. How do you respond to the first and third key changes for the Monticello EPU as noted by Mr. O'Connor?

A. Regarding the first key change of the Company obtaining the NRC licenses I have no reason to disagree that the Company has been issued the NRC licenses. Licensure is just one of the steps in NRC's approval process for operation of the Monticello EPU. Clearly, however, the Company is having trouble getting final sign off from the NRC during testing and review as it relates to the uprate ascension process of the Monticello EPU 71 MW. Specific problems appear to be due to human performance errors as discussed above. As a result, the Monticello EPU has not satisfied NRC's testing protocol and has not yet reached the 71 MW level and the EPU is not available for customer use.

For the third key change regarding the LCM/EPU split, I note that the July 17, 2014 Prehearing Order has determined this issue to be a Monticello CI issue; the Department's consultant Mr. William Jacobs addressed this issue of the LCM/EPU split through extensive discussion in his Direct Testimony in that proceeding. As a result, I will not address this issue further in this rate case proceeding. Below, I address Mr. O'Connor's second key change for Monticello EPU.

Q. What information has Mr. O'Connor provided to support Xcel's expected timeframe of NRC approval of the uprate ascension process and the process to achieve full uprate output levels?

A. On pages 6 to 15 of his Rebuttal Testimony Mr. O'Connor provided a section called "Power Ascension Process" which he believes supports the Company's claim that the Monticello EPU will achieve full uprate levels during the test year. First, on page 7 of his Rebuttal Testimony, Mr. O'Connor noted that the ascension process can take several months to complete, and final time is hard to estimate at the outset because it is difficult to predict possible anomalies experienced during the process, which must be investigated and reported to the NRC. Mr. O'Connor noted that the ascension process includes not only working with NRC, but also original equipment manufacturers and other suppliers to ensure that equipment is functioning within normal parameters and to review the data collected to support the power ascension monitoring and testing requirements. He also noted that the Company is still performing the ascension process, which the Company expects to complete later this year.

Second, he discussed on pages 10 to 12 of his Rebuttal Testimony the problems the Company experienced to date with the Monticello EPU ascension process. I note that this information appears to be consistent with the Company's response to Department information request no. 115 which I discussed above.

Third, on pages 12 and 13 he discussed the latest ascension plant milestones.

Fourth, on pages 14 and 15 Mr. O'Connor indicated that since its last rate case, the Company now has the NRC license amendment approved. He noted that the Monticello plant is achieving over 90 percent of its potential. He also noted that the Monticello plant has already reached 95 percent of its potential safely, and is expected to return to that 95 percent level by the end of August.

Q. Do you agree that Mr. O'Connor has shown that it is reasonable to conclude that the Monticello EPU will operate at its full uprate output levels within Xcel's expected timeframe of the uprate ascension process?

A. No. Primarily I note that most of Mr. O'Connor's information is generally not new information, but simply is explained in more detail than the information Xcel provided in response to Department information request no. 115, which I addressed on pages 51 to 57 of my Direct Testimony. Based on that information, I concluded that it is likely that the Monticello EPU will not be available for most if not all of the 2014 test year.

I also noted that since the EPU is not in-service, it is not reasonable for ratepayers to pay for the Monticello EPU in 2014 rates. That said, Mr. O'Connor did change the ascension plant milestones schedule on page 12 and 13 of his Rebuttal Testimony, when compared to the response the Company provided to Department information request 115 (DOC 115), which I discuss next.

Q. What differences has Mr. O'Connor provided on pages 12 and 13 of his Rebuttal Testimony?

A. First, on page 2 of its response to DOC information request no. 115, the Company indicated that it expected the reanalysis and re-verification of the model and the inputs and outputs to be completed by the end of June, and that it expected the NRC review and approval to take approximately one month such that the Company expected to re-enter ascension in August assuming no additional licensing activities are required. Now, however, Mr. O'Connor stated in his Rebuttal Testimony on page 12 that the re-analysis of the model and inputs has been submitted to Xcel for their internal review and approval – and, as of July 11, 2014, it had not been submitted to the NRC. Mr. O'Connor noted that Xcel will transmit the data to the NRC for review and approval in mid-July. He also noted that once the NRC review and concurrence of the data is complete, the plant will resume power ascension testing scheduled for August 2014.

Q. What concern do you have regarding this difference in the schedule between DOC 115 and Mr. O'Connor's Rebuttal Testimony?

A. Mr. O'Connor appears to assume that the NRC's approval will occur very soon, although he provided no specific information to support an August 2014 resumption of power ascension testing. That is, despite the Company's extension of its own timeframe for when they planned to send the data to the NRC, initially by the end of June (in response DOC 115) to now mid-July (Mr. O'Connor's Rebuttal Testimony on page 12), the Company still concluded without support that the plant will resume power ascension testing in August 2014. In addition to its own time extension, past experience has shown that the NRC schedule tends to take longer than the Company allows for in its scheduling for the Monticello license amendments.

Further, while the Department is hopeful that Xcel has addressed the NRC's concerns, the NRC still may find problems with the data and may identify problems with the power ascension testing once it resumes. Xcel simply has not provided information from which it is reasonable to conclude that the Monticello EPU is likely to be approved and in-service in 2014.

Q. What other differences did you note in the ascension schedule provided in Xcel's response to DOC IR No. 115 compared to the ascension schedule provided by Mr. O'Connor in his Rebuttal Testimony?

A. I performed a side-by-side comparison of Xcel's response to DOC information request no. 115 and page 13 of Mr. O'Connor's Rebuttal Testimony. I observed that the new August 2014 schedule appears to be the same at 1,819 MWt as it is for the Steam Dryer Data only. However, the two schedules change after August 2014 with the response to DOC 115 appearing to provide several steps and incremental power level amounts before reaching the full 2,004 MWt or 671 MWe output in December 2014. However, Mr. O'Connor's revised schedule in his Rebuttal Testimony does not include all of the same steps and incremental power level amounts, or new expected dates, and yet somehow reaches the 2,004 MWt or 671 MWe output level in early September 2014.

Q. Did Mr. O'Connor provide any support for why the timelines changed?

A. No. Mr. O'Connor did not provide any specific information to explain why Xcel took more time to provide data to the NRC or to support the accelerated timeline to power up the EPU in his Rebuttal Testimony, although he noted generally and without specifics on page 13 that the timeline provided is based on timely reviews by the vendors and NRC. He noted that if the data render unexpected results, the review times could also be impacted. My concern is that the Company's speculation regarding the accelerated timeline is unsupported by facts. Irrespective of who (Xcel, Xcel's vendors, or the NRC) may cause the actual Monticello EPU timeframe to become fully operational at a time later than Xcel now hopes, the fact remains that hope and conjecture are not substitutes for facts upon which reasoned decision-making is based. The record does not include facts from which it is reasonable to conclude that Xcel's accelerated timeframe is likely.

Q. What area of the Monticello EPU 2014 in-service date concern does Ms. Perkett address?

A. Ms. Perkett addresses the accounting in-service date for the Monticello EPU and accounting concerns with various parties' recommendations for the Monticello EPU.

Q. What information does Ms. Perkett provide regarding the accounting in-service date for Monticello EPU?

A. On page 44 of her Rebuttal Testimony, Ms. Perkett noted that the January 2015 Monticello addition of $225.5 million was placed in-service in January 2014 for accounting purposes. Ms. Perkett noted that consistent with Mr. O'Connor's Rebuttal Testimony the EPU license amendment was received by the NRC and Monticello operated at the uprate levels for more than two months during the testing process before returning to the 600 MW level to resolve testing issues. Additionally, she stated that all equipment at Monticello is being used to support ongoing plant operations.

On page 45 of her Rebuttal Testimony, Ms. Perkett explained that from an accounting viewpoint, the plant is not required to operate at the 671 MW in order for the NRC license to be in service, with the typical requirement for generation units using a 24 hours of continuous operation before placing in service. Ms. Perkett

Docket No. E002/GR-13-868
DOC Ex. ___ (NAC-S-1)

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

Xcel Energy			
Docket No.:	E002/GR-13-868		
Response To:	Department of Commerce	Information Request No.	2148
Requestor:	Nancy Campbell, Dale Lusti, Angela Byrne, Chris Shaw		
Date Received:	July 8, 2014		

Question:

Reference: DOC July 2, 2014 Direct Testimony of Campbell in Docket No. E002/CI-13-754.

Please calculate and show all calculations for the rate base, income statement and overall revenue requirement impacts for the following Monticello EPU prudency adjustment recommended by the Department for 2015:

The Department recommended a disallowance of $71.42 million on a Minnesota jurisdictional basis (including AFUDC), which is estimated to be less than a $10.713 million annual revenue requirement reduction on a Minnesota jurisdictional basis for 2015 based on our investigation of Monticello LCM and EPU projects. The Department will include the final revenue requirement reduction for Monticello CI investigation docket in the revenue requirements of DOC witness Dale Lusti in his Surrebuttal Testimony (Schedules DVL-S-4 and DVL-S-7) in this rate case proceeding.

Response:

As described in Docket No. E002/CI-13-754 (Monticello Prudence Docket), in Department of Commerce witness Ms. Nancy Campbell's Direct Testimony, and based on Exhibit ___ (NAC-1), Schedule 12 in that docket, we created a "DOC Prudence Adjustment" that removes $93.7 million from Plant In Service on a Total Company basis, depreciated accordingly over the remaining life of the plant. The corresponding tax depreciation and deferred taxes are also provided in the adjustment.

To allocate to the Minnesota electric jurisdiction, we apply the 2015 composite demand allocator of 73.9969% (Interchange Agreement demand of 84.5641% multiplied by the Minnesota jurisdictional demand of 87.5039%). We note that the

Company's methodology for calculating the 2015 jurisdictional allocators results in a slightly different jurisdictional demand allocator than the DOC used in its calculation. As a result, when our 2015 demand allocator is used, we yield a $69.3 million reduction to plant balance, on a Minnesota electric jurisdictional basis, as compared to the $71.4 million adjustment proposed by Ms. Campbell (see Campbell Direct, Schedule 12 in Docket No. E002/CI-13-754). While our numbers are different, we believe the information provided in this response and the attachments is equally applicable. Attachment A to this response provides this adjustment in Column "e", DOC Prudence Adjustment. Attachment B provides additional detail for the revenue requirement calculation. Attachment C provides the monthly detail for the adjustment.

Ms. Campbell's Direct Testimony in the Monticello Prudence Docket states that:

- The Monticello EPU is not expected to be in-service in 2014.
- The Monticello EPU is expected to be in-service and used and useful in 2015.
- The prudence disallowance should be reflected in 2015 to avoid overlap with the rate case adjustment for 2014 (not) in-service.

Ms. Campbell's Direct Testimony in the Monticello Prudence Docket did not discuss whether cost recovery for the Monticello EPU should be allowed in the Minnesota Electric Rate Case 2015 Step. However, the Rebuttal Testimonies of Company witnesses Mr. Christopher B. Clark and Mr. Jeffrey C. Robinson in this proceeding (Docket No. E002/GR-13-868) recommend that if the Commission's Order includes delayed recovery of the Monticello EPU in 2014, the Commission should then include in their final Order recovery of the 2015 revenue requirement in the 2015 Step.

Attachment A to this response therefore outlines:

- For 2014:
  - Company's request for recovery of the Monticello LCM/EPU – Column "a"
  - DOC recommended disallowance of the Monticello EPU in 2014 (rate case adjustment for in-service) – Column "b"
  - Remaining amounts to recover in the 2014 test year assuming DOC recommendation – Column "c"
- For 2015:
  - Company's request for recovery of the Monticello EPU, advanced in time for 2015 – Column "d"
  - DOC recommended disallowance of the Monticello EPU in 2015 (prudence adjustment for cost-effectiveness) – Column "e"
  - Remaining amounts to recover in 2015 assuming DOC recommendation and 2015 in-service of the Monticello EPU – Column "f"
  - 2015 Step increment assuming DOC recommendations – Column "g"

Details for the resulting 2015 Step adjustment, which should be used as the complete representation of the Department's position as relates to the 2015 Step, are provided in Attachment D.

Attachments A, B, C and D are provided in live Excel spreadsheet format.

Witness:	Anne E. Heuer
Preparer:	Charles Burdick
Title:	Principal Rate Analyst
Department:	Revenue Requirements North
Telephone:	612-330-6646
Date:	July 21, 2014

Northern States Power Company

Docket No. E002/GR-13-868
DOC Information Request No. 2148
Attachment A - Page 1 of 1

MONTICELLO LCM/EPU
Amounts in $000s

	a		b		c = a + b		d		e		f = d + e		g = f - c	
	As-Filed 2014 Test Year		**DOC rate case Adjustment**		**DOC position 2014 Level**		**Assumed 2015 In-Service**		**DOC Prudence Adjustment**		**DOC Prudence Assumed 2015 Lvl**		**DOC Prudence 2015 Step**	
		74.3399%		74.3399%				73.9969%		73.9969%		73.9969%		
		After I/A		After I/A		After I/A		After I/A		After I/A		After I/A		After I/A
Rate Analysis	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur
Plant Investment	602,187	447,665	(251,926)	(187,281)	350,261	260,384	714,759	528,899	(93,699)	(69,334)	621,060	459,565	270,799	199,181
Depreciation Reserve	45,120	33,542	(19,008)	(14,130)	26,112	19,412	85,983	63,625	(2,975)	(2,201)	83,008	61,423	56,896	42,011
CWIP	112,256	83,451	(46,699)	(34,716)	65,558	48,735	-	-	-	-	-	-	(65,558)	(48,735)
Accumulated Deferred Taxes	138,772	103,163	(57,900)	(43,043)	80,872	60,120	135,263	100,090	(18,364)	(13,589)	116,899	86,502	36,027	26,382
	530,551	394,411	(221,717)	(164,824)	308,834	229,587	493,513	365,184	(72,360)	(53,544)	421,153	311,640	112,319	82,053
Average Rate Base	530,551	394,411	(221,717)	(164,824)	308,834	229,587	493,513	365,184	(72,360)	(53,544)	421,153	311,640	112,319	82,053
Debt Return	12,097	8,993	(5,055)	(3,758)	7,041	5,235	11,252	8,326	(1,650)	(1,221)	9,602	7,105	2,561	1,871
Equity Return	27,429	20,391	(11,463)	(8,521)	15,967	11,870	25,515	18,880	(3,741)	(2,768)	21,774	16,112	5,807	4,242
Current Income Tax Requirement	24,362	18,110	(10,164)	(7,556)	14,197	10,554	24,245	17,941	(4,072)	(3,013)	20,173	14,928	5,976	4,373
Book Depreciation	40,493	30,102	(16,918)	(12,577)	23,575	17,526	41,231	30,510	(5,949)	(4,402)	35,282	26,108	11,707	8,582
Annual Deferred Tax	(3,059)	(2,274)	1,265	940	(1,794)	(1,333)	(3,959)	(2,930)	1,577	1,167	(2,382)	(1,763)	(588)	(429)
ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depr & Removal Expense	29,799	22,152	(12,486)	(9,282)	17,312	12,870	28,426	21,034	(2,342)	(1,733)	26,084	19,301	8,772	6,431
AFUDC Expenditure	605	450	(252)	(187)	353	263	-	-	-	-	-	-	(353)	(263)
Avoided Tax Interest	66	49	(28)	(21)	38	28	-	-	-	-	-	-	(38)	(28)
Total Revenue Requirements	100,717	74,873	(42,083)	(31,284)	58,634	43,588	98,284	72,727	(13,835)	(10,237)	84,449	62,490	25,815	18,901

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	5.0200%	45.3000%	2.2700%
Short Term Debt	0.6800%	2.1400%	0.0100%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.8300%	52.5600%	5.1700%
Required Rate of Return			7.4500%
	State	**Federal**	**Composite**
Tax Rates	9.8000%	35.0000%	41.3700%

2015 PRUDENCE ADJUSTMENT CALCULATIONS
($000's)

Line No.	RATE BASE Description	Total Co	MN Jur
	Electric Plant as Booked		
1	Production	($93,699)	($69,334)
2	Transmission		
3	Distribution		
4	General		
5	Common		
6	TOTAL Utility Plant in Service	($93,699)	($69,334)
	Reserve for Depreciation		
7	Production	($2,975)	($2,201)
8	Transmission		
9	Distribution		
10	General		
11	Common		
12	TOTAL Reserve for Depreciation	($2,975)	($2,201)
	Net Utility Plant In Service		
13	Production	($90,724)	($67,133)
14	Transmission	$0	$0
15	Distribution	$0	$0
16	General	$0	$0
17	Common	$0	$0
18	Net Utility Plant in Service	($90,724)	($67,133)
19	Utility Plant Held for Future Use		
20	Construction Work in Progress	$0	$0
21	Less: Accumulated Deferred Income Taxes	($18,364)	($13,589)
22	Cash Working Capital		
	Other Rate Base Items:		
23	Materials and Supplies		
24	Fuel Inventory		
25	Non-Plant Assets & Liabilities		
26	Prepayments		
27	Deferred Revenues - Nuc Outage		
28	Nuclear Outage Amortization		
29	Customer Advances		
30	Customer Deposits		
31	Sherco 3 Deferral		
32	Black Dog Reg Asset Amortization		
33	PI EPU Amortization		
34	Other Working Capital		
35	Total Other Rate Base Items		
36	Total Average Rate Base	($72,360)	($53,544)

Line No.	INCOME STATEMENT Description	Total Co	MN Jur
	Operating Revenues		
37	Retail	$0	$0
38	CIP Revenue Adjustment	0	0
39	Interdepartmental	0	0
40	Other Operating	0	0
41	**Total Operating Revenues**	$0	$0
	Expenses		
	Operating Expenses:		
42	Fuel & Purchased Energy	$0	$0
43	Power Production	0	0
44	Transmission	0	0
45	Distribution	0	0
46	Customer Accounting	0	0
47	Customer Service & Information	0	0
48	Sales, Econ Dvlp & Other	0	0
49	Administrative & General	0	0
50	Total Operating Expenses	$0	$0
51	Depreciation	($5,949)	($4,402)
52	Amortization	$0	$0
	Taxes:		
53	Property	$0	$0
54	Deferred Income Tax & ITC	1,577	1,167
55	Federal & State Income Tax	1,651	1,222
56	Payroll & Other	0	0
57	Total Taxes	$3,228	$2,389
58	**Total Expenses**	($2,721)	($2,013)
59	Allowance for Funds Used During Construction	$0	$0
60	**Total Operating Income**	$2,721	$2,013
	Calculation of Revenue Requirements		
61	Rate Base	($72,360)	($53,544)
62	Required Operating Income	(5,391)	(3,989)
63	Operating Income	2,721	2,013
64	Income Deficiency	(8,111)	(6,002)
65	Revenue Deficiency	**($13,835)**	**($10,237)**
	Calculation of Income Taxes		
66	Operating Revenue	$0	$0
67	- Operating Exp	0	0
68	- Amortizations	0	0
69	- Taxes oth than Inc	0	0
70	Operating Income before Adjs	$0	$0
71	Additions to Income	$0	$0
72	Deduct from Income	($2,342)	($1,733)
73	Debt Synchronization	($1,650)	($1,221)
74	State Taxable Income	$3,992	$2,954
75	State Income Tax before Credits	$391	$289
76	State Tax Credits	$0	$0
77	Federal Taxable Income	$3,601	$2,664
78	Fed Income Tax before Credits	$1,260	$933
79	Federal Tax Credits	$0	$0
80	Income Tax	$1,651	$1,222

Northern States Power Company

MONTICELLO LCM/EPU
Amounts in dollars

Docket No. E002/GR-13-868
DOC Information Request No. 2148
Attachment C - Page 1 of 1

			Plant In-service								Tax Depreciation				Deferred Taxes		
		Function	Beg Bal	Additions	Retirements	Transfers/ Adjustments	End Bal	Beg Bal	Provision	End Bal	Tax Composite	Federal Tax Depreciation (5)	State Tax Depreciation (32)	Avoided Tax	Beg Bal	Annual	End Bal
DOC Adjustment	2014	December					(93,699,000)			-							(19,151,982)
	2015	January	(93,699,000)	-	-	-	(93,699,000)	-	(495,762)	(495,762)	(195,206)	(195,206)	(195,206)	-	(19,151,982)	131,381	(19,020,601)
		February	(93,699,000)	-	-	-	(93,699,000)	(495,762)	(495,762)	(991,524)	(195,206)	(195,206)	(195,206)	-	(19,020,601)	131,381	(18,889,219)
		March	(93,699,000)	-	-	-	(93,699,000)	(991,524)	(495,762)	(1,487,286)	(195,206)	(195,206)	(195,206)	-	(18,889,219)	131,381	(18,757,838)
		April	(93,699,000)	-	-	-	(93,699,000)	(1,487,286)	(495,762)	(1,983,048)	(195,206)	(195,206)	(195,206)	-	(18,757,838)	131,381	(18,626,456)
		May	(93,699,000)	-	-	-	(93,699,000)	(1,983,048)	(495,762)	(2,478,810)	(195,206)	(195,206)	(195,206)	-	(18,626,456)	131,381	(18,495,075)
		June	(93,699,000)	-	-	-	(93,699,000)	(2,478,810)	(495,762)	(2,974,571)	(195,206)	(195,206)	(195,206)	-	(18,495,075)	131,381	(18,363,694)
		July	(93,699,000)	-	-	-	(93,699,000)	(2,974,571)	(495,762)	(3,470,333)	(195,206)	(195,206)	(195,206)	-	(18,363,694)	131,381	(18,232,312)
		August	(93,699,000)	-	-	-	(93,699,000)	(3,470,333)	(495,762)	(3,966,095)	(195,206)	(195,206)	(195,206)	-	(18,232,312)	131,381	(18,100,931)
		September	(93,699,000)	-	-	-	(93,699,000)	(3,966,095)	(495,762)	(4,461,857)	(195,206)	(195,206)	(195,206)	-	(18,100,931)	131,381	(17,969,550)
		October	(93,699,000)	-	-	-	(93,699,000)	(4,461,857)	(495,762)	(4,957,619)	(195,206)	(195,206)	(195,206)	-	(17,969,550)	131,381	(17,838,168)
		November	(93,699,000)	-	-	-	(93,699,000)	(4,957,619)	(495,762)	(5,453,381)	(195,206)	(195,206)	(195,206)	-	(17,838,168)	131,381	(17,706,787)
	2015	December	(93,699,000)	-	-	-	(93,699,000)	(5,453,381)	(495,762)	(5,949,143)	(195,206)	(195,206)	(195,206)	-	(17,706,787)	131,381	(17,575,406)
		2015 Total		-	-	-			(5,949,143)		(2,342,475)	(2,342,475)	(2,342,475)	-		1,576,576	
		2015 Beg/End Avg					(93,699,000)			(2,974,571)							(18,363,694)
		2015 13 Mo Avg					(93,699,000)			(2,974,571)							(18,363,694)
After DOC Adjustment	2014	December					621,060,174			65,366,895							118,090,428
	2015	January	621,060,174	-	-	-	621,060,174	65,366,895	2,940,176	68,307,071	2,173,666	1,807,286	4,395,650	-	118,090,428	(198,497)	117,891,931
		February	621,060,174	-	-	-	621,060,174	68,307,071	2,940,176	71,247,247	2,173,666	1,807,286	4,395,650	-	117,891,931	(198,497)	117,693,434
		March	621,060,174	-	-	-	621,060,174	71,247,247	2,940,176	74,187,423	2,173,666	1,807,286	4,395,650	-	117,693,434	(198,497)	117,494,937
		April	621,060,174	-	-	-	621,060,174	74,187,423	2,940,176	77,127,599	2,173,666	1,807,286	4,395,650	-	117,494,937	(198,497)	117,296,439
		May	621,060,174	-	-	-	621,060,174	77,127,599	2,940,176	80,067,775	2,173,666	1,807,286	4,395,650	-	117,296,439	(198,497)	117,097,942
		June	621,060,174	-	-	-	621,060,174	80,067,775	2,940,176	83,007,951	2,173,666	1,807,286	4,395,650	-	117,097,942	(198,497)	116,899,445
		July	621,060,174	-	-	-	621,060,174	83,007,951	2,940,176	85,948,127	2,173,666	1,807,286	4,395,650	-	116,899,445	(198,497)	116,700,948
		August	621,060,174	-	-	-	621,060,174	85,948,127	2,940,176	88,888,303	2,173,666	1,807,286	4,395,650	-	116,700,948	(198,497)	116,502,451
		September	621,060,174	-	-	-	621,060,174	88,888,303	2,940,176	91,828,479	2,173,666	1,807,286	4,395,650	-	116,502,451	(198,497)	116,303,953
		October	621,060,174	-	-	-	621,060,174	91,828,479	2,940,176	94,768,655	2,173,666	1,807,286	4,395,650	-	116,303,953	(198,497)	116,105,456
		November	621,060,174	-	-	-	621,060,174	94,768,655	2,940,176	97,708,831	2,173,666	1,807,286	4,395,650	-	116,105,456	(198,497)	115,906,959
	2015	December	621,060,174	-	-	-	621,060,174	97,708,831	2,940,176	100,649,008	2,173,666	1,807,286	4,395,650	-	115,906,959	(198,497)	115,708,462
		2015 Total		-	-	-			35,282,113		26,083,989	21,687,428	52,747,804	-		(2,381,966)	
		2015 Beg/End Avg					621,060,174			83,007,951							116,899,445
		2015 13 Mo Avg					621,060,174			83,007,951							116,899,445
Original Base - As Filed	2014	December					714,759,174			65,366,895							137,242,410
	2015	January	714,759,174	-	-	-	714,759,174	65,366,895	3,435,938	68,802,833	2,368,872	2,002,492	4,590,857	-	137,242,410	(329,879)	136,912,531
		February	714,759,174	-	-	-	714,759,174	68,802,833	3,435,938	72,238,771	2,368,872	2,002,492	4,590,857	-	136,912,531	(329,879)	136,582,653
		March	714,759,174	-	-	-	714,759,174	72,238,771	3,435,938	75,674,708	2,368,872	2,002,492	4,590,857	-	136,582,653	(329,879)	136,252,774
		April	714,759,174	-	-	-	714,759,174	75,674,708	3,435,938	79,110,646	2,368,872	2,002,492	4,590,857	-	136,252,774	(329,879)	135,922,896
		May	714,759,174	-	-	-	714,759,174	79,110,646	3,435,938	82,546,584	2,368,872	2,002,492	4,590,857	-	135,922,896	(329,879)	135,593,017
		June	714,759,174	-	-	-	714,759,174	82,546,584	3,435,938	85,982,522	2,368,872	2,002,492	4,590,857	-	135,593,017	(329,879)	135,263,139
		July	714,759,174	-	-	-	714,759,174	85,982,522	3,435,938	89,418,460	2,368,872	2,002,492	4,590,857	-	135,263,139	(329,879)	134,933,260
		August	714,759,174	-	-	-	714,759,174	89,418,460	3,435,938	92,854,398	2,368,872	2,002,492	4,590,857	-	134,933,260	(329,879)	134,603,382
		September	714,759,174	-	-	-	714,759,174	92,854,398	3,435,938	96,290,336	2,368,872	2,002,492	4,590,857	-	134,603,382	(329,879)	134,273,503
		October	714,759,174	-	-	-	714,759,174	96,290,336	3,435,938	99,726,274	2,368,872	2,002,492	4,590,857	-	134,273,503	(329,879)	133,943,624
		November	714,759,174	-	-	-	714,759,174	99,726,274	3,435,938	103,162,212	2,368,872	2,002,492	4,590,857	-	133,943,624	(329,879)	133,613,746
	2015	December	714,759,174	-	-	-	714,759,174	103,162,212	3,435,938	106,598,150	2,368,872	2,002,492	4,590,857	-	133,613,746	(329,879)	133,283,867
		2015 Total		-	-	-			41,231,256		28,426,464	24,029,903	55,090,279	-		(3,958,543)	
		2015 Beg/End Avg					714,759,174			85,982,522							135,263,139
		2015 13 Mo Avg					714,759,174			85,982,522							135,263,139

2015 STEP ADJUSTMENT CALCULATIONS
assuming DOC rate case and prudence recommendations
($000's)

Line No.	RATE BASE — Description	Total Co	MN Jur
	Electric Plant as Booked		
1	Production	$270,799	$199,181
2	Transmission		
3	Distribution		
4	General		
5	Common		
6	TOTAL Utility Plant in Service	$270,799	$199,181
	Reserve for Depreciation		
7	Production	$56,896	$42,011
8	Transmission		
9	Distribution		
10	General		
11	Common		
12	TOTAL Reserve for Depreciation	$56,896	$42,011
	Net Utility Plant in Service		
13	Production	$213,903	$157,170
14	Transmission	$0	$0
15	Distribution	$0	$0
16	General	$0	$0
17	Common	$0	$0
18	Net Utility Plant in Service	$213,903	$157,170
19	Utility Plant Held for Future Use		
20	Construction Work in Progress	($65,558)	($48,735)
21	Less: Accumulated Deferred Income Taxes	$36,027	$26,382
22	Cash Working Capital		
	Other Rate Base Items:		
23	Materials and Supplies		
24	Fuel Inventory		
25	Non-Plant Assets & Liabilities		
26	Prepayments		
27	Deferred Revenues - Nuc Outage		
28	Nuclear Outage Amortization		
29	Customer Advances		
30	Customer Deposits		
31	Sherco 3 Deferral		
32	Black Dog Reg Asset Amortization		
33	PI EPU Amortization		
34	Other Working Capital		
35	Total Other Rate Base Items		
36	Total Average Rate Base	$112,319	$82,053

Line No.	INCOME STATEMENT — Description	Total Co	MN Jur
	Operating Revenues		
37	Retail	$0	$0
38	CIP Revenue Adjustment	0	0
39	Interdepartmental	0	0
40	Other Operating	0	0
41	**Total Operating Revenues**	$0	$0
	Expenses		
	Operating Expenses:		
42	Fuel & Purchased Energy	$0	$0
43	Power Production	0	0
44	Transmission	0	0
45	Distribution	0	0
46	Customer Accounting	0	0
47	Customer Service & Information	0	0
48	Sales, Econ Dvlp & Other	0	0
49	Administrative & General	0	0
50	Total Operating Expenses	$0	$0
51	Depreciation	$11,707	$8,582
52	Amortization	$0	$0
	Taxes:		
53	Property	$0	$0
54	Deferred Income Tax & ITC	(588)	(429)
55	Federal & State Income Tax	(4,704)	(3,446)
56	Payroll & Other	0	0
57	Total Taxes	($5,293)	($3,876)
58	**Total Expenses**	$6,414	$4,706
59	Allowance for Funds Used During Construction	($353)	($263)
60	**Total Operating Income**	($6,768)	($4,969)
	Calculation of Revenue Requirements		
61	Rate Base	$112,319	$82,053
62	Required Operating Income	8,368	6,113
63	Operating Income	(6,768)	(4,969)
64	Income Deficiency	15,135	11,082
65	Revenue Deficiency	$25,815	$18,901
	Calculation of Income Taxes		
66	Operating Revenue	$0	$0
67	- Operating Exp	0	0
68	- Amortizations	0	0
69	- Taxes oth than Inc	0	0
70	Operating Income before Adjs	$0	$0
71	Additions to Income	($38)	($28)
72	Deduct from Income	$8,772	$6,431
73	Debt Synchronization	$2,561	$1,871
74	State Taxable Income	($11,371)	($8,331)
75	State Income Tax before Credits	($1,114)	($816)
76	State Tax Credits	$0	$0
77	Federal Taxable Income	($10,256)	($7,514)
78	Fed Income Tax before Credits	($3,590)	($2,630)
79	Federal Tax Credits	$0	$0
80	Income Tax	($4,704)	($3,446)

CONTESTED ISSUES

1. <u>Monticello Extended Power Uprate (EPU) 2014 In-Service Date and 2015 Prudency Adjustment:</u>

   First, as discussed in my Direct and Surrebuttal Testimonies, I continue to recommend that the 2014 depreciation expense and return on the Monticello EPU be excluded from the 2014 test year, resulting in a $31.284 million revenue requirement reduction, for the following reasons:

   - the Monticello EPU project (71 MW) will not be available for most if not all of the 2014 test year, therefore it is not reasonable for ratepayers to pay for the Monticello EPU in the 2014 test year;
   - the Monticello EPU project has not yet reached the CN-approved increase level 71 MW (671 MWe), nor has it been approved to do so; and
   - human performance errors appear to have contributed to the NRC's concerns regarding the EPU power ascension testing.

   Second, I recommended that the Monticello EPU plant be placed back into rate base in 2015 (assuming it will be in-service in 2015 as discussed in more detail below) as shown on Attachment A, column (d) in the Company's response to Department information request no. 2148. In light of the agreement announced at the evidentiary hearing between the Company and the Department regarding the terms of the Multi-Year Rate Plan (MYRP), if the Monticello EPU is not approved and does not operate successfully at the higher 671 MWe level by January 2015, the Department would support requiring Xcel to refund any amounts collected in rates through the refund mechanism for the MYRP.

   Third, I recommend for 2015 a $10.237 revenue requirement reduction (based on the assumption that the EPU will be in service in 2015) as the Department's recommended Monticello prudency adjustment in Docket No. E002/CI-13-754 as shown on Attachment A, column (e) in the Company's response to Department information request no. 2148. Mr. Lusti provides the effect of those adjustments in the Department's recommended 2015 Step (financial statements of Mr. Lusti) to reflect the 2015 adjustments shown on the Company response to Department information request no. 2148 Attachment A. DOC Ex. 435 at NAC-S-1 (Campbell Public Surrebuttal) and DOC Ex. 442 at DVL-S-4 and DVL-S-7 (Lusti Surrebuttal).

2. <u>Rate Mitigation Plans – Depreciation Reserve and Department of Energy (DOE) Payments for 2014 and 2015:</u>
   As noted in my Direct Testimony on page 94, I continue to recommend that the Commission approve the Department's 50-40-10 percent option for the 2014 to 2016 depreciation reserve give-back plus the excess DOE funds. I also agree that the correct placeholder for DOE funds is now $25.737 million, since the Company provided support for the $10.1 million lower DOE payment in the Second Supplemental Response to DOC information request no. 1180, as discussed by Xcel witness Lisa Perkett in her opening statement (this amount will be trued-up to actual DOE funds, in compliance with Xcel's requirements to return all DOE refunds to

Docket No. E002/CI-13-754
DOC Ex. ___ NAC-S-3

☐ **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:	Department of Commerce	Information Request No.	196
Requestor:	Nancy Campbell, Dale Lusti & Angela Byrne		
Date Received:	January 8, 2013		

Question:

Subject: A.S. King Plant Capital Projects
Reference: Larson Direct Testimony page 19

A. Please identify all capital projects for A.S. King Plant with 2012 and 2013 in-service dates, please include a brief description of each project, support for the cost of each project, why each project is needed, and support for the in-service date of each project.

B. Please provide support that capital projects for A.S. King Plant with 2012 and 2013 in-service dates in the 2013 test year have not already been included in the MERP plan.

C. Since A.S. King Plant was significantly updated in the MERP plan, please explain why these projects in the 2013 test year were not included in the MERP plan and are already required shortly after King in-service date for MERP plan.

Response:

A. Please see Attachment A for the list of capital project for A.S. King Plant. See the Company's response to DOC-133 for the impact of additions on depreciable life. The estimated cost and in-service date of projects are determined through the project estimating process. The response to DOC-192, Attachment G includes a summary of the project estimating process along with a checklist that is used to aid in development of project estimates.

B. The King MERP project was put in-service July 2007. The capital projects that have been completed since then were not in the scope of the MERP project. They are either emergent issues or were budgeted to be done after the MERP project.

C. The King MERP project addressed environmental concerns with a new baghouse and dry scrubber, as well as lower boiler tube replacements. The plant has many other systems that need to be maintained. If not addressed with capital projects, the safety and reliability of the plant could be affected. These projects include the upper boiler area (reheater), demineralizer, fans, controls and a feedwater heater.

Witness:	Kent Larson
Preparer:	Roger Schluessel
Title:	Regional Capital Project Director, NSP
Department:	Engineering and Construction
Telephone:	612-330-2939
Date:	January 24, 2013

A.S. King Plant Capital Projects

Parent	Description	Year	Func_class	Gp	Total	In Service Date	Project Desc	Justification
11485310	ASK1C-SCR Catalyst MiddleLayer	2012	Electric Steam Production Plant	ASK_Allen S King	$2,405,432	6/30/2012	ASK1712 - Replacement of the middle layer of SCR catalyst during the 2012 annual spring outage. The SCR Catalyst is a group of ceramic blocks that remove the ammoinafrom the flue gas. This project requires the purchase of long lead items and is scheduled to occur during the 2012 annual spring outage.	JUSTIFICATION/NECESSITY (including risks associated with project): If the catalyst is not replaced on a periodic basis, then plant operations risk significant exceedences due to NOx, ammonia slip, and or particulates. In addition as the catalyst ages the plant will be required to spray more ammonia to remove NOx, thus the cost per MW of ammoina increases.
11485233	ASK1C-Gas Recirc FanRot Assemb Repl	2012	Electric Steam Production Plant	ASK_Allen S King	$1,735,035	6/8/2012	ASK0412 - DESCRIPTION:The gas recirculation fans are used to control furnace flue gas, main steam, and reheat steam temperatures. These fans take flue gas from the economizer outlet ductwork and recirculate the flue gas back into the furnace. The recirculated gas is used to assist with the control of the main steam temperatures from the superheater. During the repowering project in 2007, the duct work was modified to accomodate the SCR and ammoinia injection grid. Since the ductwork change there has been an increased amount of fly ash erosion on the rotating assemblies. This increased rate is due to the amount of entrained fly ash in the flu gas that is entering the suction ductwork to the gas fans. During inspections in the 2010 Spring outage it was noted that there was a significant amount of wear on the fan rotor assemblies. Work was completed on the fans to restore the structural integrity of the fan rotors to return the unit back to service. The repairs were made to extend the fan life until replacement could be completed. Adequate repairs to the fan rotating assemblies cannot be completed while online due to safety related issues, no positive isolation to enter the fans. Project is for the Spring outage in 2012, but procurment of fan rotating assemblies would be needed in August 2011, for long lead time items. This project would also include the design and installtion of suction baffles to protect and extend the life of the fans.	JUSTIFICATION/NECESSITY (including risks associated with project):Avoid forced outages and extensive derates. In the event that vibrations exceed desired operational limits derates would be taken when the fan(s) are taken out of service. If one fan is taken out of service due to excessive vibrations due to erosion and ash accumulations, assume a derate of 10MW's per fan for up to 2 months, duration prior to overhaul outage, would be taken to maintain adequate steam temperatures for operation. Total derate would be 20MWhr X 24hrs/day X 62 Days 29,760 MWhr's, per fan. Annual repairs to both fans totaling ~$30,000, actual data from past work order histoy. In the event that repairs to the fans take longer than scheduled, balancing of the fans would extend the outage since both gas fans are needed for steam temperature control on start-ups. Balancing activities historically have taken 2 days to complete and for the gas fanns th unit must be offline to complete the activities. Total outage extension would be 2 days X 24 hrs X 550 MWHr's 26,400 MWHr's.
10508764	GMM0C MN Co Emergent Capital	2012	Electric Steam Production Plant	ASK_Allen S King	$715,431	12/30/2012	The MN contingency fund is for unexpected plant equipment failures.	JUSTIFICATION/NECESSITY (including risks associated with project): Equipment failures can result in unit derates, forced outages or failure to meet environmental compliance.
11544750	ASK1C-Governor Valve (Spare Pa	2012	Electric Steam Production Plant	ASK_Allen S King	$577,181	6/1/2012	DESCRIPTION: Turbine control valve system incorporates four governor valves that contol the steam to the high pressure turbine. Each governor valve is designed as a balanced single seat valve with a flow baffle. The pipe diameter is 23 1/2" OD. All the valves are surrounded by throttle pressure steam - 3500 psi at 1000 degrees. Project involves purchasing an internal valve assembly that includes valve seat, valve bell, weld-in ring, guide bushing, spindle, seal element (four of each). The cost is $512,000 for material. Valve rebuild and replacement will occur in the spring of 2012 when shops are not at peak demand and charge less to re-build. This will also allow us to meet our three week outage schedule and not extend the outage.	JUSTIFICATION/NECESSITY (including risks associated with project): During King's 2011 spring outage we inspected the four governor valves. Three of the four valves showed significant wear. New Governor Valves will save the company: 1.) expediting parts and paying a premium price to have parts reverse engineered 2.) having spare parts on hand and not using them. 3.) Governor valves will not impact the outage schedule 4.) rebuild the valves during off peak times at a reduced price.
11217851	ASK1C-HAZOP TH3 Dustless Trans	2012	Electric Steam Production Plant	ASK_Allen S King	$562,481	6/1/2012	ASK1211 - TH 3 dustless transfer. This project will install new dustless transfer chute to treat dust at its generation source, and install engineered dust collection hood to reduce windage. Install new dust collection hood on the transfer chute to control displaced induced air flow from the conveyor transfer. Install head curtains, chute seals, belt cleaners and cleaner enclosures outside of the head chute to support the dust collection. Enclose head pulleys and tail boxes. Install Dustless Transfer chambers at the chute outlet to belt load zones. Install two, higher skirt enclosures for dust settling time. Emissions point fan and dust collector are unchanged.	JUSTIFICATION/NECESSITY (including risks associated with project): Reduce coal dust hazards. This is a Hazardous Operation committee high priority recommendation because it reduces exposure to unsafe conditions or events. This project minimizes dust generation by using dustless transfer chutes which corresponds to Company compliance obligations under OSHA rules and regulations which require less than 1/32" of coal dust accumulation.

Parent	Description	Year	Func_class	Gp	Total	In Service Date	Project Desc	Justification
11485325	ASK1C-Bunker Gate Actuators	2012	Electric Steam Production Plant	ASK_Allen S King	$558,492	10/30/2013	The project would be a complete replacement all of the existing combustion air preheating steamcoils, two control valves, and associated piping and valves. There are a total of 22 steam coil sections and (2) 10" control valves that would be replaced. Each tube section assembly has square dimensions of 12' x 4' x 1' and within each assembly contains (36) 1/2" OD tubes for heat transfer. The coils should be purchased in 2013 for installation during Spring of 2014.	JUSTIFICATION/NECESSITY (including risks associated with project): Not all of the steamcoils are currently working. This project would fix those steamcoils. Additionally, several isolation valves have experienced leaks from time to time. On one occasion the valve leak caused ice buildup on a nearby forced draft fan. When the fan was started, high vibrations caused severe bearing damage. This project would resolve the potential for future mechanical issues.
11485301	ASK1C-Cyclone Inlet Exp Joint Repl	2012	Electric Steam Production Plant	ASK_Allen S King	$414,069	6/30/2012	ASK1612 - This project would replace the current slip joint style expansion joints on all twelve (12) coal supply pipes that feed each cyclone burner. The slip joints allow coal to be supplied to the burners during operation while allowing the boiler to expand and contract during load cycling.	JUSTIFICATION/NECESSITY (including risks associated with project):- The current slip joint style provides an inadequate seal and allows coal dust to escape the enclosure and accumulate on top of the buners. This project will address the safety issues that can result from the inadequate seal and accumulation of coal dust.
11485299	ASK1C-Dewater Bin Lower Gate R	2012	Electric Steam Production Plant	ASK_Allen S King	$393,419	5/31/2012	ASK1512 - DESCRIPTION:The dewatering bins are the last holding location for the bottom ash system. The dewatering bins are used to seperate out the bottom ash slag and the sluice water for shippment from the facility. The dewatering bins are of original construction with mild steel plate that has significant wear and corrosion. The scope includes the replacement of two (2) stainless steel dewatering bin discharge enclosures and two (2) carbon steel door adaptors with steam jacket connections to replace the existing carbon steel enclosure, adaptors, and sluice gates with drip pans. The material that is currently in place is mild steel and is worn to a point of potential failure. Most of the gate structure has rusted or rotted away, allowing the gates to not properly seal.	JUSTIFICATION/NECESSITY (including risks associated with project): Due to the age and condition of the material in the dewatering bins, there have been environmental leaks from time to time. This project will replace that worn material and by doing so will allow for the gates to properly seal.
11625280	ASK1C-Install Coal Silo Liners 2012	2012	Electric Steam Production Plant	ASK_Allen S King	$319,006	6/1/2012	Install new stainless steel liner on veritcal sidewalls in four coal silos (105, 106, 108, 111) during the Spring 2012 outage. The surface area of this new liner in each silo is approx. 280 square feet composed of 3/8" thick stainless. This is the first of three projects (2012, 2013, 2014) installing liners during outages.	Coal Initiative Directive. The existing guinite is falling away from the bunkers.The liners will allow wet coal to flow and not plug the silo outlet.
11485279	ASK1C-Hazardous Waste Storage Area	2012	Electric Steam Production Plant	ASK_Allen S King	$252,913	10/31/2012	Install steam heating in the old NRG boiler building. The north end of the building will be used to store waste materials (barrels, pallets, electronics, acids/caustics, etc....) and the south end of the building will be used as heated storage for the stockroom. This project also entails installing a safety shower, berms, spill cleanup material, fire detectors, roll-up door, emergency warning system, and phone system in the north end of the NRG building.	JUSTIFICATION/NECESSITY (including risks associated with project): This project will further our efforts to comply with Minnesota Pollution Control Waste Regulations, and OSHA requirements. This project will also result in the installation of a safety shower, heat, or berm system where one currently does not exist.
11350229	ASK1C-Coal Handling Slew Boom	2012	Electric Steam Production Plant	ASK_Allen S King	$162,949	12/30/2011	Replace the SCR catalyst modules in U10 HRSG. Existing catalyst will be removed and then the new modules will be installed.	JUSTIFICATION/NECESSITY (including risks associated with project): This project is needed to replace a catalyst that is not working effectively. Increasing ammonia slip shows that the catalyst is not reacting with the ammonia because it is used up.
10937228	ASK1C-2012 Boiler FW Insul & A	2012	Electric Steam Production Plant	ASK_Allen S King	$159,390	6/1/2012	ASK0212 - DESCRIPTION:Continue to remove asbestos insulation on Boiler Feedwater Line and reinsulate. The Boiler Feedwater line provides preheated water to King's Boiler. The line consists of approximately 334' of 14" piping.	JUSTIFICATION/NECESSITY (including risks associated with project): This project is needed to address safery considerations that have arisen due to the Boiler Feedwater piping exhibiting some sifting at various joints. Additionally this project leverages resources as performing abatement on the other lines in the pipe chase, at the same time, saves a redundant cost of setting up asbestos enclosures again later.

Parent	Description	Year	Func_class	Gp	Total	In Service Date	Project Desc	Justification
11485268	ASK1C-Lift Station Replace	2012	Electric Steam Production Plant	ASK_Allen S King	$145,239	1/31/2013	ASK1212 - DESCRIPTION: This project will replace the existing sanitary sewer lift station which has been in place since 1966. The lift station collects sanitary sewer waste from the plant by gravity feed, and pumps the waste uphill to the city of Oak Park Heights sanitary sewer system. The existing system pressurizes two tanks individually and pushes the sewage to a larger tank. From there sewage is pumped to the city. The new system will utilize gravity feed from the plant and then pump to the city.	JUSTIFICATION/NECESSITY (including risks associated with project): This project is needed to replace malfunctioning systems and pumps in the existing sanitary sewer lift station which have caused approximately four spills each year and resulted in greater dedication of resources over the last three years.
11573645	ASK1C-Cyclone Flame Scanner Re	2012	Electric Steam Production Plant	ASK_Allen S King	$71,465	12/30/2011	DESCRIPTION: Install new flame scanner equipment on boiler cyclones. There will be 24 scanners on the 12 cyclones on the boiler (2 per cyclone). This equipment is required to be explosion-proof. These are a critical item to the boiler safety provisions. This work can be performed with the unit online by isolating one cyclone at a time throughout the month of December.	JUSTIFICATION/NECESSITY (including risks associated with project): 1) NFPA 85 requires that two working flame scanners be in operation; one as primary and the other as the backup. 2) Existing flame scanner equipment is unique for King Plant resulting in supplier inventory risk (not as many suppliers are willing to stock this equipment). It takes up to eight weeks to procure new scanners with the old (current) design. 3) These new flame scanners include an upgrade in design providing a digital output instead of an analog output. 4) During start up we have to position employees at the cyclones and watch for ignition and a consistent flame. We have to do this becuase the current flame scanners are not reliable to pick up flame.
11565109	ASK1C-VFD Well Pumps Install	2012	Electric Steam Production Plant	ASK_Allen S King	$6,240	12/30/2011	DESCRIPTION: Install new VFD control system on two 50-HP existing deep well pumps. This project also includes the electrical (conduit, wire) and programming necessary for the system to operate properly. Roughly 125' of underground trenching (for insturmention cabling) is included for Well Pump #11.	JUSTIFICATION/NECESSITY (including risks associated with project): Installing a new VFD control system has been recommended because the existing pumps have become unreliable due to more frequent start-stop activity. This start-stop activity recently caused a shaft to break on the existing pump which cost the Company $30,000 to repair. The root cause of the shaft break was: 1) The pump(s) are short cycling; turning on for 30-45 seconds then off for 30-45 seconds. The start/stop signal is being controlled by a line pressure sensor trying to maintain 90-95 psi. 2) When the motor shuts off (for 30-45 seconds), a surge of well water flows back down the pipe causing the impeller to spin backwards. While the impeller is still spinning in the opposite direction, the motor will start up again causing an immense strain on the shaft and motor.

Parent	Description	Year	Func_class	Gp	Total	In Service Date	Project Desc	Justification
10799010	ASK1C-Reheater Tube Section Re	2013	Electric Steam Production Plant	ASK_Allen S King	$19,691,925	10/1/2013	Replacement of horizontal and pendant reheater surfaces in the boiler, including inlet and outlet headers, and installation of additional sootblowers based on modification of the reheater design. Reheater replacement will eliminate existing tubes with wall thickness less than minimum wall which have thinned due to a combination of flyash erosion, sootblower induced erosion, oxidation and internal exfoliation. Modification of the pendant reheater arrangement will provide additional space between pendants, allowing more effective cleaning of fouling deposits that accumulate when firing Powder River Basin subbituminous coal. The sootblowing arrangement in the reheater pendants will be modified. Per the preliminary design, six existing sootblowers will be relocated on the 8th and 9th floors, and six new sootblowers will be added with two on the ninth floor and 4 on the 8th floor. Six additional new sootblowers may also be added on the 8-1/2 floor, which will extend the current pendant coverage at that level. The new blowers will be long retractable IK type with normal sootblowing steam supply from either the primary superheater or from cold reheat. Piping replacements are also included in these costs.	JUSTIFICATION/NECESSITY (including risks associated with project): Reheater replacement will eliminate existing tubes with wall thickness less than minimum wall which have thinned due to a combination of flyash erosion, sootblower induced erosion, oxidation and internal exfoliation. A Condition Assessment of Critical Boiler Pressure Parts in April 2004 indicated that over 50% of RH tubes inspected had wall thickness less than the original design minimum wall. Additional examination in 2006 found 25% of RH tubes inspected were at or below of 85% of minimum wall or less.
11485290	ASK1C-Waterwall Panel Replacement	2013	Electric Steam Production Plant	ASK_Allen S King	$8,045,731	6/1/2013	ASK1412 - Replacement of 24 (20' by 20') waterwall panels due to quench cracking locates around each IKW sootblowing water lance. Extent of the cracking is deep enough that maintenance repair techniques such as weld overlay and other similar methods will be unsuccessful. An alternate sizing may be 240 panels sized 10' by 4'. Shielding and spacing has been installed to deter further degradation, however the primary damage has already occurred.Project is requested for the Spring 2013 annual outage; material would need to be purchased in the Spring/Summer of 2012.	JUSTIFICATION/NECESSITY (including risks associated with project): There have not been any forced outages due to issues on cracked waterwall tubes. However, there have been discovery work identified during planned and forced outages from other reasons.
10936995	ASK1C-Boiler Water Makeup Demi	2013	Electric Steam Production Plant	ASK_Allen S King	$2,424,788	3/5/2013	ASK1812 - Replace Boiler Water Makeup Demineralizer system and controls from 1967. The system provides 200 gpm water makeup to maintain Boiler operation, and purifies the water to prevent Tube corrosion. The system has internal redundancy to ensure a Boiler makeup supply.	JUSTIFICATION/NECESSITY (including risks associated with project): Existing systems are in need of major repair or replacement. Continued decline will cause plant forced outages. System resin tanks are routinely rinsed with acid or caustic to regenerate ion exchange functionality. All of the tanks are in need of replacement due to corrosion.
10508764	GMM0C MN Co Emergent Capital	2013	Electric Steam Production Plant	ASK_Allen S King	$1,759,503	12/30/2012	The MN contingency fund is for unexpected plant equipment failures.	JUSTIFICATION/NECESSITY (including risks associated with project): Equipment failures can result in unit derates, forced outages or failure to meet environmental compliance.
11200892	ASK1C-Ovation Controls Simulat	2013	Electric Steam Production Plant	ASK_Allen S King	$1,572,294	9/18/2013	ASK2212 - Ovation controls full fidelity Simulator provides complete access to the King Plant controls system without the concern of effecting the running unit, employees can perform operational tasks, they can be trained to react to plant failure conditions, help improve unit performance and efficiencies. The simulator also provides tuning capabilities and unit testing which if successful can then be performed on the running unit without risk.This project aligns with and is supported by the Human Performance Initiative Team.	JUSTIFICATION/NECESSITY (including risks associated with project): The simulator will assist in training of new operators. The risks associated with the project are that the Simulator does not have the desired affect and turns out to be an ineffective tool for teaching. We do not believe this is the case, as is evidenced by the numerous nuclear plants who utilize simulators to ensure their operators are well versed in the operation of those plants.

Parent	Description	Year	Func_class	Gp	Total	In Service Date	Project Desc	Justification
11485264	ASK1C-Coal Syst Controls Replace	2013	Electric Steam Production Plant	ASK_Allen S King	$1,383,082	6/15/2013	ASK1112 - The project would be a complete replacement all of the existing PLC logic controls used for the coal system with Emerson Ovation DCS - This will replace 14 PLCs that are obsolete. This is part of the coal initiative.	JUSTIFICATION/NECESSITY (including risks associated with project): The current coal system including dust collectors, dumper building , crusher building, conveyor systems, and CO monitoring are controlled via independent PLC of various manufactures, styles and PLC program systems, these are required to be maintained and monitored. The PLCs do not have redundancy and in some cases cannot be replaced like-for-like due to the age of the PLCs. In the event of a PLC failing it can cause the unit to have to be taken off-line. Due to the age of some of the PLCS it is not possible to get replacement parts, therefore requiring a complete replacement with today's PLC technology.
11217859	ASK1C-Feedwater Heater 16B Rep	2013	Electric Steam Production Plant	ASK_Allen S King	$1,335,046	6/4/2013	ASK2112 - :Replace 16B HP FW Heater as it has reached end of life. At present 5% of the tubes have been plugged (16A FWH is not far behind at 4.39%). During MERP 16B FW Heater had additional tubes blown. 16B FWHTR contains 8,830 total sq ft of surface, weighs 42.6 tons, and has contains tube and shell sides of 4700 psig @ 500 F and 425 psig @ 900 F respectively. These heaters are of orignal plant design and manufacture (1966).Note: There are long leadtimes (44+ weeks ARO) for FW heaters. This needs to be ordered in 1Q of 2012 to arrive in time for Spring 2013 outage.	JUSTIFICATION/NECESSITY (including risks associated with project): EPRI and Production Resources recommends replacement at 15% tube failure.
11485248	ASK1C-Turbine Control Syst Rep	2013	Electric Steam Production Plant	ASK_Allen S King	$1,229,857	8/7/2013	ASK1012 - Replace current turbine control system with Emerson Ovation controls for control of turbine system, Emerson Controls will be integrated into the existing plant DCS. Replacement of existing Turbo-Toc and Boiler Feed Pump Systems with Ovation control.	JUSTIFICATION/NECESSITY (including risks associated with project): Current system is obsolete and marginally supported, is not available to be manipulated by Operations, except for automated startup and shutdown, and operates on antiquated PLC logic design. Parts are becoming difficult to find and very expensive (+$10K/card, with long lead times). Resolution is to install Emerson Ovation Controls and to incorporate into existing Ovation DCS which is fully supported and parts are readily available.
11217852	ASK1C-Screenhouse TrashRake Re	2013	Electric Steam Production Plant	ASK_Allen S King	$480,166	10/15/2013	Replace the Screenhouse Trash Rake which is original plant equipment from 1967. The trash rake removes large debris from the plant Circulating Water intake to maintain water flow path for plant operation.	JUSTIFICATION/NECESSITY (including risks associated with project): The original plant equipment has failed and is not repairable. Plant is using a makeshift rake on a Grove lift to remove debris. Use of this mobile equipment has a higher safety risk with potential to tip over if the load is too large or the rake gets caught on a structure.
11217861	ASK1C-AFC-2B Flite Conveyor Re	2013	Electric Steam Production Plant	ASK_Allen S King	$402,371	5/3/2013	Replace AFC-2B with a new conveyor. A separate request has been submitted for AFC-1A. AFC-1B and AFC-2A have already been replaced. AFC-2B is over 30 years old, and will need another major overhaul in the near future due to wear on chains, buckets, wear plates, and drive system. This is an outage project.	JUSTIFICATION/NECESSITY (including risks associated with project): These conveyors supply coal to the plant coal bunkers. Since all four conveyors may be required to run to obtain full load, maintaining the conveyors prevents shutdowns due to a single conveyor failure. Installing new conveyors for the remaining old design conveyors (AFC-1A and AFC-2B) will enable common replacement parts for much of the conveyors. The new conveyors will be easier to maintain in the future due to the availability of parts.
11217860	ASK1C-AFC-1A Flite Conveyor Re	2013	Electric Steam Production Plant	ASK_Allen S King	$400,845	4/30/2013	Replace AFC-1A with a new conveyor. A separate request has been submitted for AFC-2B. AFC-1B and AFC-2A have already been replaced. AFC-1A is over 30 years old, and will need another major overhaul in the near future due to wear on chains, buckets, wear plates, and drive system. This is an outage project.	JUSTIFICATION/NECESSITY (including risks associated with project): These conveyors supply coal to the plant coal bunkers. Since all four conveyors may be required to run to obtain full load, maintaining the conveyors prevents shutdowns due to a single conveyor failure. Installing new conveyors for the remaining old design conveyors (AFC-1A and AFC-2B) will enable common replacement parts for much of the conveyors. The new conveyors will be easier to maintain in the future due to the availability of parts.

Parent	Description	Year	Func_class	Gp	Total	In Service Date	Project Desc	Justification
11629973	ASK1C-Cooling Tower Bypass	2013	Electric Steam Production Plant	ASK_Allen S King	$387,608	6/4/2013	Install a new Cooling Tower Bypass system. Install new bypass system including (2) new 30" diameter bypass systems, (1) in each of the (2) existing risers, to include: riser modifications (to direct the water to the cold water basin when the new 36" valves are closed), (2) new 36" butterfly valves, (2) new 30" butterfly valves, 3" vacuum/pressure relief valves, FRP pipe supports in the cold water basin, bypass piping in the cold water basin & stainless steel attaching hardware.	Environmental. This will help flush the tower cells during cleaning/flushing for leaves and zebra mussels.
11629976	ASK1C-Install Coal Silo Liners 2013	2013	Electric Steam Production Plant	ASK_Allen S King	$313,642	6/5/2013	Install new stainless steel liner on veritcal sidewalls in four coal silos during the Spring 2013 outage. The surface area of this new liner in each silo is approx. 280 square feet composed of 3/8" thick stainless. This is the second of three projects (2012, 2013, 2014) installing liners during outages.	Coal Initiative. The existing gunite is falling from bunkers. The liners will allow wet coal to flow better and not plug the silo outlet.
11629986	ASK1C-11 BFP Cable Replacement	2013	Electric Steam Production Plant	ASK_Allen S King	$238,742	6/10/2013	Replace two parallel 500 foot runs of 15 kV power cable to the 11 electric boiler feed pump.	JUSTIFICATION/NECESSITY (including risks associated with project): The existing cable is original plant design (more than 44 years old) and has shown signs of damage. The existing cable is an unshielded cable. This cable supplies the electric boiler feed pump, which is required to startup King Plant from an outage. This work will take five weeks for demo and installation, so Spring 2013 outage is the ideal time for this work.
11629970	ASK1C-Control Room ErgonomicUp	2013	Electric Steam Production Plant	ASK_Allen S King	$229,943	5/22/2013	Install ergonomic (sit/stand) console at the control room horseshoe and transport the existing horseshoe to the new simulator room. This work is outage work, and needs to be performed during the Spring of 2013 to take advantage of the longer outage.	JUSTIFICATION/NECESSITY (including risks associated with project): This project was recommended by the Company's ergonomic specialist to accommodate a varying height of the workforce.
11629971	ASK1C-Generator Relay Panel Repl	2013	Electric Steam Production Plant	ASK_Allen S King	$183,134	6/3/2013	Replace existing generator protection relays with a multifunction relay; replace the KWH meters with new ones; and replace the lockout relays with new ones. These will be installed in the Relay Room, so that the generator panel in the Control Room can be removed. This requires a long outage, and the 2013 outage would be best to perform this work.	JUSTIFICATION/NECESSITY (including risks associated with project): This project is needed to replace equipment that is at, near or has exceeded its useful life.
11629985	ASK1C-Yard Swtchgr BldgHoist Instal	2013	Electric Steam Production Plant	ASK_Allen S King	$117,509	10/21/2013	Install new 2-ton electric hoist and six-foot monorail in the switchgear building. Install new porch on building.	JUSTIFICATION/NECESSITY (including risks associated with project): Support future breaker preventive maintenance and battery replacement efforts.
11629984	ASK1C-ID Fan BldgRoof AccessInstall	2013	Electric Steam Production Plant	ASK_Allen S King	$117,006	10/22/2013	Install 580 linear feet of 36" anti-slip walkway with handrail on the roof of ID Fan Building.	JUSTIFICATION/NECESSITY (including risks associated with project): This project is needed to further the safety of our employees at the King plant. This will install anti-slip walkway.
11629968	ASK1C-SDA Atomizer VibrationMonitor	2013	Electric Steam Production Plant	ASK_Allen S King	$116,910	10/4/2013	Install new vibration monitoring equipment and wells for the three existing atomizers. There are two monitors per atomizer and one spare. There are no removal costs associated with this project.	JUSTIFICATION/NECESSITY (including risks associated with project): The existing atomizers do not have vibration monitoring. This addition would increase the amount of time between PMs. Currently two atomizers per week are getting PMs in fear of loosening bolts between the gearbox and flexshaft of the atomizers. PMs usually take 1 full day for 2 maintenance plus one electrican and operator support. Having the seismic probes would allow for longer runs between PMs, as well as an early indicator of imbalance of the wheels.

Parent	Description	Year	Func_class	Gp	Total	In Service Date	Project Desc	Justification
11629942	ASK1C-AQCS Pressure Washers	2013	Electric Steam Production Plant	ASK_Allen S King	$105,071	8/29/2013	Install a 2500 psi, 4 GPM pressure washer in each the SDA Penthouse and the Lime Prep Building. The proposed system will have multiple wand locations, and also have the capability to reach all spots in each of the buildings that require pressure cleaning. There are no removal costs associated with this project.	JUSTIFICATION/NECESSITY (including risks associated with project): In 2009 a pressure washer was installed to clean grit screens in the Lime Prep Building. This installation has worked well, so a request has been made to install another pressure washer in the SDA penthouse. (The current pressure wash cannot reach the SDA penthouse from its current location). The proposed system will have multiple wand locations, and the proposed system will also have the capability to reach all spots in the building in need of pressure cleaning. The alternative of using the LIme prep area high pressure hydrolazer is not recommended due to safety concerns with the 20,000 psi output, and likely damage to the screens the operators are cleaning, especially considering the frequency of use.
11629966	ASK1C-Econ Ash Slide Gates	2013	Electric Steam Production Plant	ASK_Allen S King	$80,709	6/4/2013	Install pneumatic operators on 12" valve at the bottom of econ hoppers. Tie-in position indication (open/close) to DCS. The existing valves are standard gate valves.	JUSTIFICATION/NECESSITY (including risks associated with project): Automation will remove safety risks for plant employees.

Docket No. E002/CI-13-754
DOC Ex. ___ NAC-S-4

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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.	127
Requestor:	Nancy Campbell/Chris Shaw		
Date Received:	August 29, 2014		

Question:

Reference: DOC July 2, 2014 Direct Testimony of Campbell on page 27 in Docket No. E002/CI-13-754 for the $402.1 million cost overrun

Please calculate and show all calculations for the rate base, income statement and overall revenue requirement impacts for the following possible Monticello LCM and EPU projects prudency adjustments:

a) Calculate the effect of no rate of return on the $402.1 million cost overrun amount for the Monticello LCM and EPU projects for the 2015 step year.

b) Calculate the effect of no rate of return on the $402.1 million cost overrun amount for the Monticello LCM and EPU projects for the remaining life of the project in total, and showing the amounts by year.

c) Calculate the effect of a weighted short-term and long-term debt return on the $402.1 million cost overrun amount for the Monticello LCM and EPU projects (consistent with the calculation for Prairie Island Extended Power Uprate as discussed on page 6 of Dale Lusti's Surrebuttal Testimony in Docket No. E002/GR-13-868) for 2015 step year.

d) Calculate the effect of a weighted short-term and long-term debt return on the $402.1 million costs overrun for the Monticello LCM and EPU projects amount (consistent with DOC recommendation for Prairie Island Extended Power Uprate as discussed on page 6 of Dale Lusti's Surrebuttal Testimony in Docket No. E002/GR-13-868) for the remaining life of the project in total, and showing the amounts by year.

Response:

Please see Attachment A to this response for the computation of the revenue requirement impact of no return on rate base as requested in parts a) and b) above.

Please see Attachment B to this response for the computation of the revenue requirement impact of the Dale Lusti recommended weight debt return (zero cost of equity) as requested in parts c) and d) above.

It is important to clarify that the Company does not agree that the $402.1 million figure accurately reflects the difference between the initial estimate and the final total cost. The DOC calculated $402.1 million by using the difference between the $346 million used in modeling and the final total cost of $748 million, which includes AFUDC. Rather, the difference should be $748 million minus the sum of $346 million escalated to 2014 (or $397.5 million) and approximately $45.5 million of AFUDC. That difference is $305 million instead of $402.1 million.

Please note that the Company calculated the impacts in this information request based solely on the $402.1 million figure, as requested and will provide the same calculations using the $305 million figure upon request.

Preparer:	Michael Bliss
Title:	Rate Analyst
Department:	Revenue Requirements - North
Telephone:	612-330-6216
Date:	September 11, 2014

2015 Hearing Capital Structure			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.9400%	45.6100%	2.2500%
Short Term Debt	1.1200%	1.8900%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.8300%	52.5000%	5.1600%
Required Rate of Return			7.4300%
Tax Rate (MN)	41.3700%		

Allocation
84.5641%
87.5039%
73.9969%

(000's)

Total Company	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Plant Investment	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)
Depreciation Reserve	(12,765)	(38,295)	(63,825)	(89,356)	(114,886)	(140,416)	(165,946)	(191,476)	(217,006)	(242,537)	(268,067)	(293,597)	(319,127)	(344,657)	(370,187)	(392,526)
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	(74,443)	(72,460)	(69,845)	(66,669)	(62,619)	(57,923)	(53,198)	(48,474)	(43,750)	(39,026)	(34,303)	(29,579)	(24,744)	(18,948)	(11,280)	(3,468)
Total Rate Base	(314,892)	(291,345)	(268,429)	(246,075)	(224,596)	(203,762)	(182,956)	(162,150)	(141,343)	(120,537)	(99,731)	(78,924)	(58,229)	(38,495)	(20,633)	(6,106)
Average Rate Base	(314,892)	(291,345)	(268,429)	(246,075)	(224,596)	(203,762)	(182,956)	(162,150)	(141,343)	(120,537)	(99,731)	(78,924)	(58,229)	(38,495)	(20,633)	(6,106)
Tax Preferenced Items:																
Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Return	(7,148)	(6,614)	(6,093)	(5,586)	(5,098)	(4,625)	(4,153)	(3,681)	(3,208)	(2,736)	(2,264)	(1,792)	(1,322)	(874)	(468)	(139)
Equity Return	(16,248)	(15,033)	(13,851)	(12,697)	(11,589)	(10,514)	(9,441)	(8,367)	(7,293)	(6,220)	(5,146)	(4,072)	(3,005)	(1,986)	(1,065)	(315)
Current Income Tax Requirement	(11,465)	(10,608)	(9,773)	(8,959)	(8,177)	(7,419)	(6,661)	(5,904)	(5,146)	(4,389)	(3,631)	(2,874)	(2,120)	(1,402)	(751)	(222)
Book Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Deferred Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes																
Total Revenue Requirements	(34,862)	(32,255)	(29,718)	(27,243)	(24,865)	(22,558)	(20,255)	(17,952)	(15,648)	(13,345)	(11,041)	(8,738)	(6,446)	(4,262)	(2,284)	(676)

Minnesota	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Plant Investment	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)
Depreciation Reserve	(9,446)	(28,337)	(47,229)	(66,120)	(85,012)	(103,903)	(122,795)	(141,686)	(160,578)	(179,469)	(198,361)	(217,253)	(236,144)	(255,036)	(273,927)	(290,457)
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	(55,086)	(53,618)	(51,683)	(49,333)	(46,336)	(42,861)	(39,365)	(35,869)	(32,374)	(28,878)	(25,383)	(21,887)	(18,310)	(14,021)	(8,347)	(2,566)
	(233,010)	(215,586)	(198,629)	(182,088)	(166,194)	(150,777)	(135,382)	(119,986)	(104,590)	(89,194)	(73,798)	(58,402)	(43,087)	(28,485)	(15,268)	(4,518)
Average Rate Base	(233,010)	(215,586)	(198,629)	(182,088)	(166,194)	(150,777)	(135,382)	(119,986)	(104,590)	(89,194)	(73,798)	(58,402)	(43,087)	(28,485)	(15,268)	(4,518)
Tax Preferenced Items:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Return	(5,289)	(4,894)	(4,509)	(4,133)	(3,773)	(3,423)	(3,073)	(2,724)	(2,374)	(2,025)	(1,675)	(1,326)	(978)	(647)	(347)	(103)
Equity Return	(12,023)	(11,124)	(10,249)	(9,396)	(8,576)	(7,780)	(6,986)	(6,191)	(5,397)	(4,602)	(3,808)	(3,014)	(2,223)	(1,470)	(788)	(233)
Current Income Tax Requirement	(8,484)	(7,849)	(7,232)	(6,630)	(6,051)	(5,490)	(4,929)	(4,369)	(3,808)	(3,248)	(2,687)	(2,126)	(1,569)	(1,037)	(556)	(165)
Book Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Deferred Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Revenue Requirements	(25,796)	(23,867)	(21,990)	(20,159)	(18,399)	(16,692)	(14,988)	(13,284)	(11,579)	(9,875)	(8,170)	(6,466)	(4,770)	(3,154)	(1,690)	(500)

2015 Hearing Capital Structure			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.9400%	45.6100%	2.2500%
Short Term Debt	1.1200%	1.8900%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.8300%	52.5000%	5.1600%
Required Rate of Return			7.4300%
Tax Rate (MN)	41.3700%		

DOC Recommended Adjustment			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.9400%	45.6100%	2.2500%
Short Term Debt	1.1200%	1.8900%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	0.0000%	0.0000%	0.0000%
Required Rate of Return			2.2700%
Tax Rate (MN)	41.3700%		

Weighted Cost
0.0000%
0.0000%
0.0000%
5.1600%
5.1600%

Allocation
84.5641%
87.5039%
73.9969%

(000's)

Total Company	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Plant Investment	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)	(402,100)
Depreciation Reserve	(12,765)	(38,295)	(63,825)	(89,356)	(114,886)	(140,416)	(165,946)	(191,476)	(217,006)	(242,537)	(268,067)	(293,597)	(319,127)	(344,657)	(370,187)	(392,526)
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	(74,443)	(72,460)	(69,845)	(66,669)	(62,619)	(57,923)	(53,198)	(48,474)	(43,750)	(39,026)	(34,303)	(29,579)	(24,744)	(18,948)	(11,280)	(3,468)
Total Rate Base	(314,892)	(291,345)	(268,429)	(246,075)	(224,596)	(203,762)	(182,956)	(162,150)	(141,343)	(120,537)	(99,731)	(78,924)	(58,229)	(38,495)	(20,633)	(6,106)
Average Rate Base	(314,892)	(291,345)	(268,429)	(246,075)	(224,596)	(203,762)	(182,956)	(162,150)	(141,343)	(120,537)	(99,731)	(78,924)	(58,229)	(38,495)	(20,633)	(6,106)
Tax Preferenced Items:																
Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Equity Return	(16,248)	(15,033)	(13,851)	(12,697)	(11,589)	(10,514)	(9,441)	(8,367)	(7,293)	(6,220)	(5,146)	(4,072)	(3,005)	(1,986)	(1,065)	(315)
Current Income Tax Requirement	(11,465)	(10,608)	(9,773)	(8,959)	(8,177)	(7,419)	(6,661)	(5,904)	(5,146)	(4,389)	(3,631)	(2,874)	(2,120)	(1,402)	(751)	(222)
Book Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Deferred Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes																
Total Revenue Requirements	(27,713)	(25,641)	(23,624)	(21,657)	(19,767)	(17,933)	(16,102)	(14,271)	(12,440)	(10,608)	(8,777)	(6,946)	(5,125)	(3,388)	(1,816)	(537)

Minnesota	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Plant Investment	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)	(297,541)
Depreciation Reserve	(9,446)	(28,337)	(47,229)	(66,120)	(85,012)	(103,903)	(122,795)	(141,686)	(160,578)	(179,469)	(198,361)	(217,253)	(236,144)	(255,036)	(273,927)	(290,457)
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	(55,086)	(53,618)	(51,683)	(49,333)	(46,336)	(42,861)	(39,365)	(35,869)	(32,374)	(28,878)	(25,383)	(21,887)	(18,310)	(14,021)	(8,347)	(2,566)
	(233,010)	(215,586)	(198,629)	(182,088)	(166,194)	(150,777)	(135,382)	(119,986)	(104,590)	(89,194)	(73,798)	(58,402)	(43,087)	(28,485)	(15,268)	(4,518)
Average Rate Base	(233,010)	(215,586)	(198,629)	(182,088)	(166,194)	(150,777)	(135,382)	(119,986)	(104,590)	(89,194)	(73,798)	(58,402)	(43,087)	(28,485)	(15,268)	(4,518)
Tax Preferenced Items:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Equity Return	(12,023)	(11,124)	(10,249)	(9,396)	(8,576)	(7,780)	(6,986)	(6,191)	(5,397)	(4,602)	(3,808)	(3,014)	(2,223)	(1,470)	(788)	(233)
Current Income Tax Requirement	(8,484)	(7,849)	(7,232)	(6,630)	(6,051)	(5,490)	(4,929)	(4,369)	(3,808)	(3,248)	(2,687)	(2,126)	(1,569)	(1,037)	(556)	(165)
Book Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Deferred Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Revenue Requirements	(20,507)	(18,974)	(17,481)	(16,025)	(14,627)	(13,270)	(11,915)	(10,560)	(9,205)	(7,850)	(6,495)	(5,140)	(3,792)	(2,507)	(1,344)	(398)

Docket No. E002/CI-13-754
DOC Ex. ___ NAC-S-5

☐ **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.	135
Requestor:	Nancy Campbell/Chris Shaw		
Date Received:	September 5, 2014		

Question:

On page 33 of his rebuttal testimony, Mr. Sparby stated that he is "concerned about the impact of the Department's proposal on the financial health of the utility." Please provide copies of all reports available to Xcel regarding the effects of the Department's recommendations on the financial health of Xcel.

Response:

Mr. Sparby's testimony is based on an overall concern that a material disallowance may result in an adverse financial impact on the Company over the long term. In making this statement, Mr. Sparby was not relying on any specific report or investor comment.

Rather, Mr. Sparby was the Chief Financial Officer of Xcel Energy Inc. from 2009-11 and has experience in the types of issues that concern the capital markets. He recognizes that while difficult, the Company could absorb the direct financial impact of a disallowance in the amount recommended by the Department in this proceeding. However, his concern is not limited to the direct financial impact of a material disallowance or the impairment of the Monticello asset.

If the Commission adopts the Department's recommendation, it will have two additional impacts that raise concerns about the financial health of the utility. First, it would be the first time in Northern States Power Company's history to suffer such a material financial impairment of a major asset and the asset is viewed favorably in aggregate, so the circumstances surrounding this disallowance of this magnitude is not of the more traditional situation where the utility pursues a project that was not viewed as providing benefits to the State. As a result, he believes that in a period of significant capital investment, that adoption of the Department's narrow view of the

EPU costs as a separate project will have an adverse impact on investor perceptions about the Company and its regulatory climate.

Second, Mr. Sparby is concerned that the investor community will view the application of "cost-effectiveness" disallowance suggested by the Department as a significant change in the prudent investment standard applicable to utilities as it dismisses that the resource in total is cost effective and relies on a new split and the final cost to determine cost effectiveness. Investors generally rely on the paradigm where utilities are judged on the basis of the prudence of their decisions and actions of what they knew or should have reasonably known at the time they are made. Imposing a disallowance on the basis of an after-the-fact view of the cost-effectiveness of the ultimate investment would be viewed as a change of precedent that we are concerned would impact investors' perceptions.

Preparer:	David M. Sparby
Title:	Senior Vice President & Group President, Revenue President & CEO, NSP - Minnesota
Department:	Northern States Power Company
Telephone:	612-330-7752
Date:	September 17, 2014