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February 17, 2015

<u>ELECTRONIC FILING</u>

Mr. Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101

Re: *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*
MPUC Docket No. E002/CI-13-754
OAH Docket No. 48-2500-31139

Dear Mr. Wolf:

Enclosed for filing in the above-referenced proceeding, please find Xcel Energy's Reply Exceptions.

Please contact me if you have any questions regarding this filing.

Sincerely,

/s/ Alison C. Archer

Alison C. Archer

Enclosure
cc: Attached Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Betsy Wergin	Vice Chair
Nancy Lange	Commissioner
Dan Lipshultz	Commissioner
John Tuma	Commissioner

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

XCEL ENERGY'S REPLY EXCEPTIONS

February 17, 2015

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I. INTRODUCTION AND SUMMARY

Northern States Power Company d/b/a Xcel Energy provides the following Reply to the Exceptions of the Office of the Attorney General (OAG) and the Xcel Energy Large Industrial customers (XLI).[1] OAG and XLI largely support the ALJ's factual findings, but disagree with the Department, the ALJ, and each other with respect to an appropriate remedy. The OAG and XLI suggest that any doubt as to the prudence of the Company's actions can and should result in a broad disallowance of Program costs.[2]

XLI's proposed remedy of no return on $402 million (all costs over the high-end $346 million Certificate of Need cost estimate) would result in a revenue requirement reduction of $25.796 million (compared to the Department's recommended $10.237 million reduction). We note that while XLI asserts that its remedy only denies a return on the investment, for financial reporting purposes we would be required to take a substantial one-time write-off.

The OAG's remedy is even more severe. Disallowing $261 million, plus $19 million in change orders, plus 10 percent of any amounts over the claimed $428 million cost increase ($40 million), plus no return on any amounts recovered over $320 million, equates to more than the properly-calculated amount of the cost increase on the Project.

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[1] Because the Department of Commerce did not file Exceptions, we refer the Commission to our initial Exceptions for the reasons the portions of the ALJ Report accepting the Department's positions are unsupported by a thorough review of the record. We do not take exception here to the OAG's preference regarding the manner in which the ALJ characterized certain OAG positions; we explain here and in our initial Exceptions why we believe the OAG's position is unsupported regardless of how it is characterized in the Report.

[2] *E.g.,* OAG Exceptions at 6; XLI Exceptions at 3.

We believe both of these remedies are excessive and are not supported by the record. Our concern is rooted in the fact that both the OAG and XLI contend that any costs above the original Certificate of Need estimate, for a complex project that spanned several years, could be disallowed based on "doubts" of prudence, regardless of the evidence or cause of the escalated costs.[3] Under their theory, even if the evidence shows that substantial portions of our cost increases were prudently incurred, all costs above the original estimate could nevertheless be disallowed. This theory also implies that the Company should have achieved a result that no other nuclear operator achieved in recent years – bringing the project in at its original estimate. Lastly, the OAG and XLI positions include no consideration of the impact of their proposed remedies.

We respectfully request that the Commission reject the remedies recommended by the OAG and XLI because policy and precedent each require a more disciplined analysis and tailored remedy based on substantial evidence in the record.[4] We believe it is important to recognize there can be some imperfection in cost estimation and implementation, as well as construction issues with vendors and labor, in with a project of this size, complexity, and NRC oversight. Any remedy structured around

[3] If this were the standard, contested cases would be largely unnecessary – the parties could, as XLI and the OAG largely did in this case, appear and cast doubts rather than provide evidence of imprudence. However, Minnesota law calls for evidentiary proceedings to assess the facts regarding the quality of the utility's performance because due process requires that record evidence support findings of imprudence to avoid confiscatory results. *See St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n*, 251 N.W.2d 530, 358 (Minn. 1977) (quasi-judicial determinations made by the Commission must be supported by substantial evidence). In addition, the language in Minn. Stat. § 216B.03 that any doubt be resolved in favor of customers comes from the just and reasonable rate statute, which applies to the amount of costs and does not state that any doubt regarding the prudence of the Company's decisions and actions should result in a broad disallowance. Even when applying the just and reasonable rates standard, the Commission is charged with considering the right of the utility and its investors to a reasonable return, while at the same time establishing a rate for consumers that reflects the cost of service rendered plus a 'reasonable' profit for the utility. *N. States Power Co. v. Minnesota Pub. Utils. Comm'n*, 344 N.W.2d 374, 378 (Minn. 1984)

[4] *In re Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 38 (Jan. 11, 2010) ("claim has not been proven by the substantial evidence required for a finding of imprudence.").

the use of our original cost estimate holds the Company to a new standard that is neither related to the prudent utility standard or to meeting its burden of proving costs were prudent.

We recognize that the record in this matter is complex and that the substantial Monticello LCM/EPU Program cost increases created concerns whether the costs were incurred in customers' interests. However, that complexity does not justify the OAG's and XLI's presumption that we met none of our burden and therefore deserve extensive disallowance of cost recovery. The record is detailed precisely because we explained why costs increased for this complicated project, why cost increases were unavoidable, and why the ultimate cost of the Program was what it ultimately needed to be to achieve the goals of preserving the Monticello asset for an additional 20 years.

While we recognize that the burden is on the Company, we respectfully submit that the OAG's and XLI's positions – that any doubt(s) with respect to any aspect(s) of the Company's performance supports a material impairment of the asset – does not recognize the prudence of any of our decisions and is not proportionate to any harm caused by any imprudence or failure to prove that all of our costs were prudent.

If the Commission concludes that we were not prudent with respect to every decision or action at every step, any remedy should be specific to actions or decisions, and should be reasonably tailored to the gaps in proof. If the Commission believes a remedy is warranted, the tailored approach is most consistent with the purpose of a prudence investigation.

In sum, the OAG and XLI positions in their respective Exceptions have two major flaws. First, like the ALJ report, their positions ignore most of the record and rest merely upon "doubts" that are untethered to the record evidence. Second, both parties compound this error by advocating a broad remedy instead of tailoring such remedy to any limited finding of imprudence. To address these issues we organize the remainder of this Reply to show:

- *The correct initial cost estimate;*

- *The OAG and XLI proposed disallowances are inconsistent with the record; and*

- *The OAG and XLI remedies are excessive and not supported by law or public policy.*

II. CLARIFYING THE COMPANY'S INITIAL COST ESTIMATE

The OAG's Exceptions (p. 10-13) acknowledge confusion about the aggregate cost numbers used in this proceeding. As the Commission considers the record, it is helpful to understand the true cost increase, as it will be important to use the aggregate cost numbers consistently on an apples-to-apples basis. In order to assist the Commission with that analysis and respond to the OAG's uncertainty, we provide the following discussion from the record.

A. Calculation of $320-346 Million Initial Estimate

The OAG spends considerable time in its Exceptions questioning why the Company discusses an initial cost estimate range of $320-346 million. That is easily explained, as we provided the information in the record. $320-346 million represents the range of potential costs modeled in the 2008 EPU Certificate of Need, as described in the record as follows:

- The initial authorization for the Program in 2006 was for $273 million ($2006$) to complete LCM/EPU modifications that the Company identified.[5]

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[5] Ex. 3, O'Connor Direct at 46:5-10. Given General Electric's history with EPUs, Xcel Energy reasonably relied upon the estimate for the EPU work developed by General Electric. Ex. 3, O'Connor Direct at 47:18-49:2.

- We later added funds for the Steam Dryer and escalation to 2008 dollars.[6] The resulting base number was $320 million. The $320 million estimate was a capital cost estimate only,[7] which did not include AFUDC or amounts for third-party installation.[8]

- In the 2008 EPU Certificate of Need we modeled the $320 million base cost and also modeled a sensitivity of $346 million including additional contingency to show a range of possible costs based on the information available at the time.[9]

The OAG's Exceptions do not acknowledge that this was explained in Mr. O'Connor's pre-filed testimony or that this explanation is consistent with the testimony by Company witnesses Mr. Weatherby and Mr. Alders cited in the OAG's Exceptions.

B. Appropriate Comparisons Between Initial and Final Cost

The OAG's proposed remedy is based on the difference between the low end of our initial $320-346 million 2008 cost estimate (unescalated and without AFUDC) and the $748 million final 2013 cost (with AFUDC). Similarly, XLI's remedy is based on the difference between the high end of our initial $320-346 million 2008 cost estimate (unescalated and without AFUDC) and the $748 million final 2013 cost (with AFUDC). These are apples-to-oranges comparisons. The correct comparison should recognize the higher initial cost estimate of $346 million that was included in our Certificate of Need filing, and should escalate the estimates provided in 2008 dollars[10] to present day dollars to compare properly with final costs. Finally, an accurate

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[6] Ex. 3, O'Connor Direct at 29:14-30:3; 24:11, 47:1-3 and 30:2 at Table 5.

[7] Ex. 3, O'Connor Direct at 29:15-18.

[8] Ex. 3, O'Connor Direct at 47:1-3.

[9] Ex. 16, O'Connor Surrebuttal at 8:9-16 and 9:24-26; *see* Ex. 9, O'Connor Rebuttal at 43:22-26; Ex. 3, O'Connor Direct at 29:15-18 and 30:2 at Table 5.

[10] Ex. 3, O'Connor Direct at 29:14-30:3 and 30:2 at Table 5; Ex. 15, Alders Surrebuttal at 15:9-11.

comparison must consistently include or exclude AFUDC on both sides of the equation.

Creating a correct comparison between early and final project cost estimates requires escalation of the $346 million high end of our initial cost estimate range from 2008 dollars to present day dollars, which equates to $397.5 million without AFUDC.[11] Adding AFUDC to that number brings the total to $453 million, which provides an apples-to-apples comparison with the $748 million final cost with AFUDC.[12] The net difference in this scenario is $295 million, rather than the $402 million as XLI claims[13] or $428 million as OAG claims.[14]

Comparing the escalated initial capital cost estimates without AFUDC of $665 million to final costs without AFUDC of $397.5 million[15] would also be valid. This net difference is $268 million and could also be available under the OAG's or XLI's theories.

III. THE RECORD DOES NOT SUPPORT BROAD DISALLOWANCES

As noted above, the OAG's and XLI's proposed remedies are based on a premise that all cost increases above our initial Certificate of Need cost estimates are inherently

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11 Ex. 15, Alders Surrebuttal at 15:14-15.

12 Ex. 15, Alders Surrebuttal at 15:12-15.

13 XLI asserts a difference between initial and final estimates of $402.1 million, which uses the high end of our initial cost estimate ($346 million) but fails to escalate that number to present day dollars or apply AFUDC to our initial estimate. Again, including AFUDC on both sides of the equation and escalating the 2008 cost estimate to present dollars illustrates an overall Program cost increase of $295 million – indicating that the XLI's view of the cost increase is overstated by $107.1 million.

14 The OAG suggests the difference between our initial estimate and final costs is $428 million, based on subtracting the unescalated initial cost estimate of $320 million without AFUDC to the final cost with AFUDC of $748 million. This incorrect number is likewise referenced in Report at Findings of Fact ¶ 110. The OAG's view of the cost increases is overstated by $133 million.

15 As discussed earlier, this number represents the $346 million escalated to present day dollars.

suspect and subject to broad disallowances if there is any doubt about the Company's prudence.[16]

The OAG's and XLI's proposed remedies also rely heavily on the ALJ's Conclusion 8 that all cost increases related to the 13.8 kV distribution system, the feedwater heaters, and certain (unspecified) installation costs were imprudent. Because the focus of Conclusion No. 8 is the 13.8 kV system and feedwater heater modifications, we provide additional unrebutted detail from the record, below, to explain the need for these modifications, the specific initial cost estimates for these modifications, and the detailed reasons why their costs increased. This important evidence underscores that a remedy, if any, for imprudence or failure to meet our burden of proof should be limited, because the record is clear that these cost increases were neither avoidable nor predictable as a whole.

When evaluating this information, the Commission should take into account three of the key arguments raised to support OAG's and XLI's broad cost disallowance proposals: (i) unnecessary scope growth, (ii) installation challenges and project management issues, and (iii) the implementation schedule led to cost increases. The following discussion illustrates that these conclusions are not accurate. We further urge the Commission to note the significant extent to which this information is not referenced or otherwise acknowledged in the ALJ's Report. Overall, the detailed evidence summarized below supports rejecting the remedies proposed by the OAG and XLI.

[16] *See, e.g.,* OAG Exceptions at 6; XLI Exceptions at 3.

A. The Scope and Cost of the 13.8 kV and Feedwater Heater Replacements Were Prudent.

1. *13.8 kV Distribution System Cost Increases Were Prudent and Important*

The following table summarizes the final costs of the 13.8 kV system, which the Company will discuss below:[17]

13.8 kV Cost by Category (Million $)

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

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

a. Development of the initial cost estimate

When the Program was first conceived in 2006, the Company knew it needed to do work on the internal electrical system. The existing 4 kV system was operating at close to capacity already and the addition of any significant load would call for expansion of that capacity. Over time the Company had significantly increased electric loads with new equipment at the plant. As described in detail in our response

[17] Rather than footnote each sentence, we provide this discussion in narrative form for the ease of the reader. Unless otherwise noted, all statements in this section are supported by record evidence contained in one or more of the following:

Ex. 3, O'Connor Direct at Schedule 28 (nine page summary of 13.8 kV system costs, work, and photos);

Ex. 9, O'Connor Rebuttal at Schedule 35 (seventy-seven page collection of Company Responses to Department Information Requests on the 13.8 kV system, PowerPoint presentations, and reports from the "Electrical Summit");

Ex. 3, O'Connor Direct at Schedule 8 (Company response to DOC IR 160, which addressed the reasons for cost increases);

Ex. 3, O'Connor Direct at 89-90, 130-136;

Ex. 9, O'Connor Rebuttal at 92-102;

Ex. 16, O'Connor Surrebuttal at 10-12;

Ex. 11 Sieracki Rebuttal at 6, 36-40; and

Ex. 4, Stall Direct at 54-60.

to DOC IR-83, the existing 4 kV electrical busses were operating very close to maximum electrical fault ratings and needed to be supplemented or replaced regardless of the uprate.[18]

The higher loads also meant that under normal plant conditions using the 4 kV system, we experienced under-voltage conditions when starting large motors and pumps. The Company successfully managed this under-voltage situation by sequencing starting large and competing loads. The Company previously installed an under-voltage relay system that acted as a timer on the voltage excursions. Using that system, so long as an under-voltage event was resolved promptly it would not create any problems. However, operating in the under-voltage condition over the long run was unacceptable from an NRC compliance perspective; the Company's expert Mr. Stall was critical of exploring another 4 kV solution. Dr. Jacobs acknowledged that under-voltage conditions indicated the need for substantial work on the system.[19]

Despite this successful management of the situation in the short term, it was a clear signal that it was necessary to increase the margin in the electric system. The Company considered adding new electrical capacity through additional 4 kV busses, weighed alternatives, performed a cost/benefit analysis that concluded the cost to upgrade the existing 4 kV Distribution System was approximately the same as a new 13.8 kV Distribution System, and ultimately decided to install a new 13.8 kV Distribution System.[20]

In particular, during September 2007, Xcel Energy convened an "Electrical Summit" to evaluate options for the electrical system at the plant. The Electrical Summit

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[18] Ex. 9, O'Connor Rebuttal at Schedule 35 at 14-16 (Response to DOC IR-83); *see also* Ex. 9, O'Connor Rebuttal at Schedule 32 at 11-15 (Response to DOC IR-124).

[19] Dr. Jacobs conceded that these issues necessitated work on the 13.8 kV distribution system, although he did not examine what work would be required. Tr. Vol. IV (Jacobs) at 34:23-35:7.

[20] Ex. 3, O'Connor Direct at 131:1-132:2; Ex. 11, Sieracki Rebuttal at 38:21-39:5.

attendees included site personnel and representatives from General Electric and Shaw. The team evaluated two primary electrical options for feasibility, cost, and schedule impact. The first option involved the replacement of the 1R transformer with a similar design, replacement of the 4 kV breakers with 3305 MVA breakers, and additional bus bracing. The second option involved replacement of the 1R and 2R transformers to supply new 13.8 kV busses to feed the Reactor feed pump, condensate pumps and recirculation MG set motors. Additional meetings with site management, General Electric and Shaw were conducted to evaluate cost and schedule information for the various options. Cost estimates provided by General Electric and Shaw indicated that the incremental additional cost associated with the 13.8 kV system was less than one percent over the new 4 kV bus alternatives. Larger 8000 HP motors necessary for the Plant equipment we were installing are typically designed to 6.9 kV or 13.8 kV due to the required starting currents.

Ultimately, the Company concluded that a new 13.8 kV bus was the preferred option (over new 4 kV or 6.9 kV) based on these factors:

- *Comparability of modification and replacement cost estimates.* The estimated cost to modify and upgrade the existing 4 kV distribution system was essentially the same as the estimated cost to replace the 4 kV system; the existing configuration of Monticello was such that an additional bus could not be located in the same place as the current electric busses. Regardless of whether we placed capacity at the new bus at modern 13.8 kV levels or maintained all electric loads with obsolete 4 kV equipment, the costs of stringing cable over 14 miles would have been the same.

- *Inadequate margin.* The original electrical distribution system was designed in the early to mid-1960s. The 4 kV system was no longer adequate to support operations, and created risk of trips. Absent an upgrade in the electrical system, motor trips or plant transients were likely to occur;

- *Obsolescence.* Evolving industry standards were causing other plants to upgrade original distribution system and the 4 kV system would have needed to be upgraded or replaced to support Monticello's extended operations and the Company was in the process of removing 4 kV components from portions of its transmission system; and

- *General Electric opinion.* General Electric originally advised Xcel Energy that modification of the 4 kV system was feasible, but as planning progressed General Electric advised Xcel Energy that failure to implement the 13.8 kV system would place operating margins of the electrical distribution system at unacceptable levels.

The work between the Company, General Electric, and Shaw resulted in the decision to add new electrical capacity to the system and to include two new 13.8 kV busses in the scope of the Program. Simultaneous with that high-level decision, the Company was finalizing its Certificate of Need filing. While no detailed design or engineering work had begun on the 13.8 kV system, the Company estimated the cost of the 13.8 kV system at $20.9 million based on data from General Electric.[21]

While complex, it was simpler and safer to install the 13.8 kV system than to modify or replace the 4 kV system on a piecemeal basis. The safety busses on the 4 kV system were not designed to be taken out of service at any time because they were required to operate 24/7 due to its support of safety-related equipment. If the Company had to modify or replace the 4 kV system, it would have had to build a redundant system (*i.e.*, separate busses) to ensure continuity of service while constructing the new system. Such a course would have been highly inefficient and would not have resulted in the additional benefits arising from the 13.8 kV system. As such, it was more practical to install the 13.8 kV system as it could be constructed in parallel while the old system remained intact. And because the 13.8 kV system provided increased operating margins, portions of the 13.8 kV system – rather than the entire 4 kV system – could be taken out of service as plant conditions warrant.

[21] This estimate comes from our Supplemental Response to DOC IR 160 (Ex. 3, O'Connor Direct at Schedule 8 at Table 2).

This improved plant flexibility. The Company also recognized that the change proposed allowed creation of a spare 4 kV breaker that could be used in the event of equipment failure in the future, as parts to repair this equipment were difficult to find and no new 4 kV equipment was being manufactured. This redundancy also improved reliability over the extended life of the facility.

In addition, regardless of the selected voltage, we would have needed to locate new equipment at a discrete location due to space constraints around the existing buss work. This meant that we would have encountered the requirement to pull 14 miles of new cable either way. And either configuration would have required significant new equipment. In light of this, the decision to install the new distribution capacity at the higher and more robust voltage made much more sense. The Company concluded that the cost of the 13.8 kV system was within one percent of the cost of installing a lower voltage.[22] Indeed, because a lower voltage system would have required larger cable to make up for the lower voltage, the cost of the lower voltage option could have ended up being more expensive.[23]

b. Explanation of 13.8 kV system cost increases

The Company identified substantial cost increases for the 13.8 kV system for three reasons. First, we identified the need to increase our initial estimate when our design engineering was underway and long lead-time components were ordered in June 2009. At that time we increased our estimate of $20.9 million by approximately $15.59 million.

Second, we increased our authorization for the 13.8 kV work by approximately $35.7 in December 2011. This authorization followed the spring 2011 implementation

[22] Ex. 3, O'Connor Direct at 131:18.

[23] Ex. 16, O'Connor Surrebuttal at 11:23-12:14 (discusses the need to string 14 miles of cable which would have been required regardless of the chosen voltage).

outage. Based on the challenges in that outage, we determined that the amount of time and costs associated with completing these very complex tasks were higher than we previously expected.

Third, in December 2012, we received additional information from Bechtel that led to increasing the total estimate of the 13.8 kV modification to $105.2 million or an additional $33 million. This was due to the completion not just of detailed designs, but also of the work packages that specified tasks and the sequencing of them through the course of an outage. Over the course of about a year and three separate estimates, Bechtel's view of the work grew from $50 million to $90 million to approximately $105 million. The last estimate was based on completed detailed design, nearly complete work planning and a detailed walk down of the plant by Bechtel's subcontractors. Nevertheless, the cost to perform the installation increased significantly due to increased craft hours needed to install the complex equipment, resulting in final costs reaching $119.5 million.

Overall, costs increased because the scope of work for the 13.8 kV system increased, and the labor, *i.e.*, union man-hours (discussed below), necessary to complete the scope of work grew dramatically. The following table compares the initial scope of work upon which the initial $20.9 million cost estimate was based to the final scope after engineering, design, and implementation were completed:

13.8 kV Scope Development

PRELIMINARY SCOPE	FINAL SCOPE
☐ Replacement of 1R and 2R Transformers ☐ Installation of Switchgear Busses & Load Centers ☐ Installation of Cabling and Bus Duct ☐ Removal and Installation of Recirculation Pump Motors ☐ Replacement of Breaker Maintenance Facility ☐ Program Management Engineering Support and ☐ Testing	☐ Replacement of existing 1R and 2R transformers. ☐ Installation of fire detection and suppression systems in the 1R and 2R transformer bays. ☐ Installation of new 15 kV power cables and raceways with associated supports from the ☐ 1R and 2R transformers to busses 11 and 12. ☐ Demolition of 4 kV busses 11 and 12. ☐ Installation of new control cable and raceways with associated supports. ☐ Demolition and decontamination of existing Hot Shop. ☐ Erection of new 13.8 kV switchgear rooms in previous Hot Shop room. ☐ Installation of two new 13.8 kV switchgear lineups. ☐ Installation of HVAC for the new switchgear rooms. ☐ Installation of fire detection system in switchgear rooms. ☐ Installation of vertical lift from 911' to 931' in turbine building. ☐ Installation of new Hot Shop in Radwaste shipping building (including HVAC). ☐ Relocation of rigging storage cages to Reactor Building 985' elevation. ☐ Removal and installation of the reactor recirculation motor-generator (RRMG) drive motors. ☐ Installation of new 15 kV power cables to reactor feed pumps, condensate pumps, and reactor recirculation motor-generator drive motors. ☐ Demolition of secondary containment at RRMG set room to facilitate removal and installation of motors. ☐ Installation of digital process computer system and associated system points for six new associated equipment systems, 1R and 2R transformers, and new 13.8 kV busses 11 & 12. ☐ Removal of the switchyard current limiting protector and associated disconnects. ☐ Removal of breaker 3N5. ☐ Automatic tap changers were installed on 1R and 2R transformers (old 1R had fixed tap changers). ☐ Modify cable feeder from 2RS to 2R. ☐ Testing.

The most notable of these scope changes from a cost perspective was the location of new switchgear rooms to accommodate new busses (which would have been required regardless of the chosen voltage). This in turn necessitated pulling the 14 miles of heavy cable to the new location. The aforementioned December 2012 revised estimate from Bechtel estimated the new installation effort required to cover all the work at 59,000 man-hours (equivalent to 2,491 twenty-four hour days), which had to be performed during the confines of limited pre-outage and outage periods. The labor required to complete the work was still higher.

c. No party challenged final scope of 13.8 kV system

As noted in our initial Exceptions, no party contended that any work within the final scope of work should not have been performed or that the work was unnecessary. In particular, Mr. Crisp took no issue with "the reasonableness of decisions to add what's included in the final scope" of the 13.8 kV system and did not offer any testimony on the "reasonableness of costs" associated with its final work scope.[24] And Dr. Jacobs agreed that the system needed to be upgraded because of the under-voltage alarms we were experiencing.[25]

d. Explanation of the final 13.8 kV system cost

By far the most expensive component of the 13.8 kV system was labor, which in turn was driven by the overall scope of the 13.8 kV modifications, the craft labor shortage, and new NRC work rules discussed in our initial Exceptions. Ultimately, the Company has no control over prevailing wage labor rates and labor availability. And the cost to pull 14 miles of cable weighing in excess of one-hundred pounds per linear foot, which "trains" of 10 electricians pulled by hand 10 to 20 feet at a time, does not become less expensive by completing more design work up-front. Nor can difficult, complex work in the nuclear safety environment be completed faster just to save cost.

[24] Tr. Vol. III (Crisp) at 26:17-27:14.

[25] Tr. Vol. IV (Jacobs) at 34:23-35:7.

While the parties challenge our initial cost estimates for the 13.8 kV system and overall installation, we utilized multiple industry expert contractors who likewise underestimated the cost of labor work and revised the estimates provided to the Company multiple times.[26] Like our experts, the Company had no basis to increase cost estimates until new information became available.

In addition, the planning for the 2013 outage, during which the 13.8 kV system was completed, was completed well in advance. Bechtel took over project management right after the 2011 outage. As a result, Bechtel had nearly two years to prepare the detailed work packages and develop a well-sequenced implementation schedule with the full input and engagement of the site, working from the efforts already undertaken in the early planning phases. Nonetheless, the costs of this modification increased dramatically while Bechtel was on the job due largely to labor.

Overall, the following describes the Company's final costs on the 13.8 kV system by category:

- *Design/Engineering.* We incurred approximately $23.9 million in design and engineering costs. The original scope for this modification was to maintain the existing 4 kV distribution system and perform minor equipment enhancements to support the Program. Throughout the design process we identified a number of obstacles for successful installation of the new 13.8 kV switchgear. In 2010, after design progressed to a detailed level, we identified that the transformers could not fit within the existing transformer footprints. We convened a 13.8 kV team in January 2010 to evaluate all design considerations and project risks and determine a suitable modification plan. The team identified viable options for location of the

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[26] OAG has criticized the Company for not hiring Bechtel earlier, but Bechtel declined to bid for the project in the early Program phases due to Bechtel's own business needs. Ex. 3, O'Connor Direct at 49:22-50:10. However, Bechtel joined the Program as the primary contractor after the 2011 outage because of its depth and experience in the electrical work we faced in the 2013 outage. Ex. 9, O'Connor Rebuttal at 69:12-70:3; Tr. Vol. I (O'Connor) at 98:2-15. Bechtel is a world-class engineering firm. Ex. 16, O'Connor Surrebuttal at 12:23-24. Based on their information, it is unfair to suggest the Company's cost estimating efforts should have been better.

switchgear and presented recommendations to the Executive Committee in February 2010. We also incurred design/engineering costs to relocate our existing 'hot shop' equipment and to decontaminate the former hot shop to house the new 13.8 kV system. In converting the hot shop to the location for the new 13.8 kV system, a new HVAC system with additional particulate filter capability was required to ensure the air and space were sufficiently clean to support this high voltage equipment. Any disallowances associated with the design or engineering of the 13.8 kV system would be covered within the analysis of potentially duplicative design costs on pages 78-80 of Mr. O'Connor's Rebuttal Testimony and pages 86-88 in our Exceptions.

- *Materials/Components.* We incurred approximately $10.3 million in materials and component costs. These are the costs to acquire the materials and components necessary to complete the 13.8 kV modification. We encountered a few difficulties with certain vendors and this led to the need to stop their work or reorganize our vendor relationships to better manage the work. The equipment costs themselves, however, did not increase as a result of any of these issues and our additional oversight costs were small in the scheme of the entire project.

- *Installation.* We incurred approximately $73.2 million in installation costs. These are the costs to install the components and materials into the plant and turnover the new 13.8 kV system to operations. The primary reason that the installation costs exceeded original estimates was the difficulty and complexity of routing the new power and control cables throughout the plant, which did not become apparent until actual design and implementation were underway. Both occurred well after the initial cost estimate was created and even after some of the detailed design was completed. As one part of the process for routing these cables, it was necessary to build new pull boxes to prevent cable tension acceptance criteria from being exceeded. For the 2013 outage Bechtel estimated that installation of the 13.8 kV system would require over 59,000 hours (equivalent to 2,491 days) over 152 days.

e. <u>Conclusion</u>

The 13.8 kV modification cost $119.5 million compared to the initial estimate of $20.9 million. While that cost increase was substantial and unexpected, it was not imprudent. As the above discussion makes clear, the Company was diligent in identifying the upgrades that were necessary to serve the plant's interests and picked viable and reasonable alternatives. While the OAG and XLI question whether such costs were prudently incurred, they offer no evidence to suggest that the Company implemented the wrong work or could have done it at less expense.

The Commission should take a realistic view of when costs were incurred and decisions made. The slippery slope theory advocated by the OAG and XLI to justify large disallowances is not consistent with either the timing or the management oversight of the costs for this project. No cost components were deemed by anyone to have been avoidable. The installation costs were well-managed and necessary to support reliable plant operations. The equipment purchased was required to build the scope, and our common costs for things like scaffolding, security and training were prudent and unchallenged on this record. The only issue that can be reasonably challenged is whether we spent more than needed by engaging more than one design contractor. Thus, any proportionate remedy for either failure to meet our burden to establish prudence or alternatively imprudence, must be much smaller than the ALJ's Conclusion No. 8 and the parties reliance on it to fashion their remedies.

2. Feedwater Heaters Cost Increases Were Prudent and Important

The following table summarizes the final cost of the feedwater heaters, which the Company will discuss below:[27]

[27] Rather than footnote each sentence, we provide this discussion in narrative form for the ease of the reader. Unless otherwise noted, all statements in this section are supported by record evidence contained in one or more of the following:

Ex. 3, O'Connor Direct at Schedule 25 (four page summary of feedwater heaters cost, work and photos);

Ex. 9, O'Connor Rebuttal at Schedule 32 (discussion of feedwater heaters in the context of LCM/EPU split);

Ex. 9, O'Connor Rebuttal at Schedule 36 (technical discussion of feedwater heater scope and background);

Ex. 3, O'Connor Direct at 38-39, 117-122 (feedwater heaters testimony);

Ex. 9, O'Connor Rebuttal at 58, 103-106 (feedwater heater testimony);

Feedwater Heater Cost by Category (Million $)

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

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

a. Development of the initial cost estimate

Feedwater heaters are essentially large heat exchangers that heat the feedwater prior to injection in the core. These heat exchangers have to withstand high temperatures and velocities of the water traveling in and out. As a result, they are susceptible to corrosion and degradation and must be re-rated or replaced over time. The 14 A/B and 15 A/B feedwater heaters (four total) at Monticello were original vintage equipment in the plant. The 13 A/B heaters were 30 years old.

The initial scope of this Program modification proposed by General Electric was to re-rate (*i.e.*, recertify at higher operating levels) the existing feedwater heaters without replacement or substantial construction. The Company based its initial cost estimate for the feedwater heaters totaling $37.0 million on that level of work.

The estimate included rerating six feedwater heaters (12, 14, and 15 A/B heaters), replacing drain and dump valves, replacing only the cross around relief valves (CARVs) (not the associated piping), rerating drain coolers, testing main steam navy nipples, and making modifications to the moisture separator drain tank (MSDT).

Ex. 16, O'Connor Surrebuttal at 13-15 (feedwater heater testimony);

Ex. 11 Sieracki Rebuttal at 34, 53 (feedwater heater testimony);

Ex. 4, Stall Direct at 45-47 (feedwater heater system testimony).

b. Explanation of feedwater heater cost increases

The Company subsequently decided to remove Feedwater Heater No. 12 and replace the 13/14 and 15 A/B heaters given their age and condition. This was an option that was available to us under the General Electric contract and was an efficient way to combine needed LCM work with the uprate.

During the design phase, the Company concluded that six feedwater heaters (13 A/B, 14 A/B and 15 A/B) needed to be replaced due to their aging condition and signs of wear. In other words, the heaters were near the end of their useful life. The results from testing showed that tubes were becoming plugged at an increasing rate; tube leaks had become more common; and it was clear that the existing heaters were degraded. This phenomenon is normal in the life-cycle of heat exchanges and becomes a problem only if a sufficient amount of the tubes have become plugged that it degrades performance. Service-related degradation was the primary consideration in our ultimate decision to replace rather than repair the six feedwater heaters that were part of the Program. Testing performed in conjunction with design work showed that they had degraded to the point where further tube plugging was not a viable long-term option.

Moreover, the Company recognized that further repair of this system would not be sufficient and that replacement was in the best interests of the plant. Substantial maintenance requiring longer refueling outages to re-tube the heat exchangers was not desirable even without EPU required capacity change. Six of the ten feedwater heaters in the Plant were down to minimal code-allowable metal thickness. At some point, this wear leads to the need to rebuild the feedwater heaters, which can be an expensive undertaking. It was normal in the industry to replace feedwater heaters well before the 40 year mark.

After the decision to replace rather than re-rate the heaters had been made, an occurrence in 2010 confirmed the soundness of the Company's decision. In mid-2010, the 15 B heater began to have significant problems with tube leaks and experienced a malfunction every couple of weeks. By October of that year the problem became so severe that the Company was required to undertake a controlled shutdown of the plant to fix the plugged tubes and the tube leaks. This resulted in an outage of about one week and made it abundantly clear that there was an urgent need to replace the heaters.

The scope of work for the feedwater heater modification changed substantially during the design of the Program. Several changes besides replacing rather than re-rating heaters were made, including drain and dump piping, turbine floor modifications, main steam thermowell installation, and CARVs. The most notable scope additions (and primary cost drivers) were:

- *Replace 13 A/B, 14 A/B, and 15 A/B Feedwater Heaters*: The equipment costs for replacement of the heaters was approximately five times the costs as compared to the initially-anticipated rerating. That in turn, drove labors cost up. The 14 A/B and 15 A/B heaters were original equipment and we could no longer continue to modify and repair the shell and tube heat exchangers. The condition of the 13 A/B feedwater heaters during inspections indicated that replacement was necessary. We determined that we could rerate the 11 and 12 feedwater heaters and did that.

- *Turbine Floor 951'*: The decision to replace the 14 A/B and 15 A/B feedwater heaters with larger heaters required structural analysis and reinforcement of the turbine floor. The initial feedwater heaters were undersized and the need to install slightly larger equipment was likely to be needed without the uprate.

- *Replace Drain and Dump Piping*: We decided to replace hundreds of feet of piping with larger piping and remove associated asbestos insulation to accommodate the extended life of the Plant. This piping replacement likely could have been delayed to another outage, but because substantial feedwater heater work was underway it was most cost-effective to undertake

> the replacement concurrent with the other work. Replacement of the piping was completed at a cost of approximately $30 million. We relied primarily on as-builts for design of the piping but were required to make several in-outage design modifications because of in-plant conditions identified during outages.

Other cost increases stemmed from difficulties in removing and replacing the actual heaters and installing vents, drains, and piping. Most scope additions, such as the need to replace vents and drain piping for the 14 A/B and 15 A/B feedwater heaters, structural analysis and reinforcement of the turbine floor, and drain cooler penetration locations were not related to the small footprint of the plant. Another example concerns the 13 A/B feedwater heaters, which are located under the turbine floor of the Plant. When the 13 A/B feedwater heaters were replaced in the 1980s, the removal and reinstallation had been challenging because of the size of the access hatch, which allows entry beneath the turbine floor where they are located. To accommodate the rigging for the 13 A/B feedwater heater removal and installation, we decided to make the hatch a bit larger. This work was necessitated by the decision to replace rather than re-rate the feedwater heaters. To be clear, it had nothing to do with the minor increase in size (5 inches) of the new heaters as Mr. Crisp suggested and the ALJ Report concludes.[28]

The following table indicates the initial scope of work upon which the initial $37.0 million cost estimate was based as compared to the final scope, after engineering, design and implementation were completed:

[28] Report at Findings of Fact ¶ 76.

Feedwater Heater Scope Development

PRELIMINARY SCOPE	FINAL SCOPE
• Feedwater heaters: o Rerate 12, 14, and 15 feedwater heaters, o Rerate dump and drain piping, and o Rerate drain coolers and install bypass; • Replace CARV – piping and setpoints; • Modify navy nipples; • Modify MSDT with condensate injection; and • Testing.	• Replace and rerate feedwater heaters: o Replace six feedwater heaters (13 A/B, 14 A/B, 15 A/B); o Replace discharge nozzles on three of four low pressure feedwater heaters (11 A/B, 12 A) with larger diameter nozzles; o Replace 400 feet of dump and drain insulated piping and remove asbestos insulation from existing piping; o Install two four ton jib cranes; o Replace dump and drain venting and valves; and o Replace drain coolers. • Replace CARV piping and establish new setpoints. • Enlarge Turbine Floor #2 Hatch. • Reinforcement of Turbine Floor 951'. • Remove and cap main steam thermowell. • Modify main steam Navy Nipples. • Modify MSDT. • Replace Feedwater Flow Transmitters. • Testing.

c. No party challenged scope of feedwater heater work

As with the 13.8 kV distribution system, no party contended that part of the final feedwater heater scope of work should not have been performed. The Company's testimony that all feedwater heater work was necessary was unrebutted. Mr. Crisp, in fact, took no issue with the "reasonableness of decisions reflecting the final scope of the feedwater heater project" and did not offer any testimony on the "reasonableness of the final cost" associated with the final scope of work.[29]

[29] Tr. Vol. III (Crisp) at 25:15-26:13.

d. Explanation of final feedwater heater costs

The final cost for this entire modification was $114.9 million. A large portion of this cost was incurred due to the replacement rather than rerate of six of the Plant's ten feedwater heaters. As with the 13.8 kV system, the most expensive component of the feedwater heater replacement was labor. At $59.5 million, it accounted for more than half of the $114.9 million final cost. In addition, other components of the labor included asbestos abatement, weld evaluations, x-ray radiography, related electrical work, testing and work caused by twenty-two "interferences" identified as design progressed.

The other large component of expense was design and engineering. The Company utilized multiple contractors for engineering and design of feedwater heaters, piping, loading and support, engaged in new piping design for CARVs, and made design changes to feedwater heater piping to avoid interferences, which required additional analysis. Any disallowances associated with the design or engineering of the feedwater heaters would be covered within the analysis of potentially duplicative design costs on pages 78-80 of Mr. O'Connor's Rebuttal Testimony, which was included in our Exceptions.

Finally, the same fallacies embraced by the parties' various requests for disallowances of large portions of the major modifications discussed with respect to the 13.8 kV system apply equally to the feedwater heaters. While the Department and OAG question the Company's initial cost estimates overall,[30] they did not contest the initial decision to move from a rerate to replacement due to the age and condition of the equipment. Nor did they assess whether any labor savings could actually have been achieved by rendering a higher early cost estimate. As such, the record does not support findings of imprudence (or broadly targeted failure to meet our burden), let

[30] XLI simply adopted the Department's position and proposed a different remedy.

alone an extensive disallowance of the cost increases or of a return on all cost increases.

The OAG endorses the ALJ's finding that the "much larger" size of new feedwater heaters was the primary reason for the cost increases. This conclusion is both incorrect and does not change that the work needed to be done in any case to keep Monticello running. The record shows that the new 13 A/B heaters were less than five inches larger than those being replaced.[31] As Mr. O'Connor testified, we recognized that replacing the heaters was going to be very challenging even if we had replaced them with ones of the same size, as these heaters were located under the floor, such that access was more difficult on both removal and installation than would normally be the case.

Moreover, like the 13.8 kV system, the majority of the feedwater heater effort is disassociated both in time and in management from any causal effort to link cost overruns to initial decisions, because much of the specific work was planned for and implemented after the 2011 outage. No one deemed any of the cost components to have been avoidable. Like with the 13.8 kV system, any proportionate remedy for either failure to meet our burden to establish prudence, or alternatively imprudence, must be much smaller than the ALJ's Finding No. 8 and the parties' reliance on it to fashion their remedies. An accurate review of the evidence would establish that the difference between initial cost estimates and final costs had more to do with the final design of the heaters and the craft labor issues the Company encountered than with the size of the replacements. Because the heaters had to be replaced in any case to keep Monticello operating, this cost was unavoidable.

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[31] Ex. 16, O'Connor Surrebuttal at 14:15-15:4 (The new "feedwater heaters are the same length as the old ones and are less than five inches wider than the old ones. Given the historic concerns with the access hatch size and the 13A/B feedwater heater replacement rigging, however, we likely would have had to make the access hatch larger even absent the uprate.").

e. Conclusion

The feedwater heaters modification cost $114.9 million compared to the initial estimate of $37 million. That cost increase was again substantial, but it was not imprudent. As the above discussion makes clear, the Company recognized that this legacy equipment needed to be replaced irrespective of the uprate and was diligent in identifying the work that was necessary to serve the plant's interests. Ultimately, the challenges of installing these heat exchangers were significant but the cost, while high, was not imprudent and was unavoidable.

B. Other Cost Increases Were Prudent and Important

The 13.8 kV distribution system and feedwater heaters are two important examples of modifications where costs increased, and where the parties and ALJ assumed cost increases were imprudent without assessing the overall drivers of these increases. We focus on these two modifications because they were specifically addressed in both the ALJ Report and the OAG's Exceptions. However, they are by no means the only examples of prudent decision-making described in the record.

To further illustrate our prudence and the impropriety of sweeping remedies based on doubts, Attachment A to these Reply Exceptions provides similar analyses for the condensate demineralizer, reactor feed pumps and motors, licensing costs, and "other modifications" including the turbine, steam dryer, and power range neutron monitoring system (PRNM). We provide these analyses to illustrate the complexity of the Program, our detailed decision processes, and the specific causes of cost increases that do not warrant the extensive remedies as advocated by the OAG and XLI.

IV. OAG AND XLI REMEDIES ARE INCORRECT AND EXCESSIVE

The OAG and XLI criticize the Department's 'cost-effectiveness' remedy as insufficient and as somehow creating an incentive for the Company to spend too much. We believe the Department's remedy is overstated; in addition, there is no such incentive. Xcel Energy operates via a cost-based model in which the utility is permitted to recover its prudently incurred costs and risks disallowance of any costs found to have been imprudent.[32] This creates a tremendous incentive to act prudently and be able to prove it. Under the unique circumstances of this case, where the nuclear regulatory world changed dramatically for the Company and other nuclear operators, allowing recovery of our costs creates no improper incentive. Rather, it recognizes that our decisions were appropriate even where we increased the size of the investment for the good of the plant and our customers.

The OAG's and XLI's much more extreme remedies are based on their formation of a cost recovery barrier that no utility could surmount – essentially, that doubts regarding the Company's prudence inherently exist with respect to any dollar incurred above initial planning-level estimates, and that such doubts, even if devoid of evidentiary support in the record, could and should lead to broad disallowances.

We highlighted the key decisions the Company made throughout the record. They included: (1) hiring General Electric as the design contractor because it was the original equipment manufacturer, a decision that Mr. Crisp testified was "absolutely" reasonable;[33] (2) initial decisions to modify certain scopes to support long term operations of the plants – decisions with which Mr. Crisp testified he found no fault;[34] (3) the decision to move forward with a 2009 and 2011 outage schedule, which was

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[32] Ex. 8, Alders Rebuttal at 28:13-25.

[33] Tr. Vol. III (Crisp) at 32:17-19.

[34] Tr. Vol. III (Crisp) at 24:10-27:14. Further, Dr. Jacobs acknowledged that he did not analyze what work needed to be done to support long-term operations of the plant so could not criticize the work we did. Tr. Vol. IV (Jacobs) at 36:11-15. And Dr. Jacobs agreed that low-voltage alarms meant an upgrade of the electrical system was overdue, Tr. Vol. IV (Jacobs) at 34:23-35:7, and that it is common to need to replace feedwater heaters as part of a life-extension project. Tr. Vol. IV (Jacobs) 30:6-10; Ex. 428, *In re Nuclear Cost Recovery Clause*, Fla. Pub. Serv. Comm'n No. 080009-EI, REVISED DIRECT TESTIMONY AND EXHIBITS OF WILLIAM R. JACOBS, JR., PH.D. at 9:5-16 (July 30, 2008).

one of two options recommended by GE; was supported by the then- anticipated capacity needs and energy markets; and was slowed as appropriate to assure quality installation by rejecting non-conforming equipment and inadequate designs;[35] (4) the decision to select Day Zimmerman as the implementation contractor for the 2009 outage, which was supported by the facts that only Day Zimmerman and General Electric responded to the Company's RFP for installation services and that Mr. Crisp acknowledged installation work was not within General Electric's wheelhouse;[36] (5) the decision to hire alternate design contractors to improve on designs supported by the reliability needs of the plant and our concerns about costs of implementing the initial reactor feed pump designs;[37] (6) our decision to retain Day Zimmerman for the 2011 outage after our current Chief Nuclear Officer and then Monticello Site VP personally assessed their performance and also concluded that continuity was an important consideration;[38] (7) our decision after the 2011 outage to move certain work to Bechtel – supported by the fact that the nature of the work was moving from mechanical to electrical and that we could retain continuity by using Day Zimmerman as the lead mechanical subcontractor;[39] and (8) our decisions to enhance the scope where appropriate to assure the efficient long-term operations of the plant.

Overly broad statements of failure to meet our burden, and conclusions of imprudence by an OAG non-engineer witness, are premised primarily on statements of doubt about the Company's performance and should not lead to presumptions of

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[35] Ex. 9, O'Connor Rebuttal at Schedule 20 (Company Response to Department IR 41 regarding implementation schedule choices).

[36] Tr. Vol. III (Crisp) at 36:14-37:2. Indeed, General Electric informed the Company that their expertise was not in implementation and recommended that someone else take that role. Tr. Vol. I (O'Connor) at 107:15-23.

[37] Ex. 9, O'Connor Rebuttal at 42:14-21.

[38] Ex. 3, O'Connor Direct at 75:13-76:8.

[39] Ex. 9, O'Connor Rebuttal at 70:1-3.

broad imprudence or extensive disallowance of unavoidable costs.[40] Based on the discussion above regarding our key decisions and actions with respect to the modifications on which the ALJ focused, these assumptions are unfair and inaccurate.

Moreover, basing a remedy on the assumption that all increases over a Certificate of Need-level estimate are suspect would retroactively change the way costs are recovered. A retroactive cap on Certificate of Need-level estimates would shift the regulatory paradigm under which the Company was operating when it developed high level initial estimates for the Program. At that time, parties recognized that many factors are unknown when the Commission is first assessing the need for a project – especially for a complex construction matter in the nuclear field as opposed to projects where costs are largely known.[41] The idea of caps on costs at the Certificate of Need state did not emerge until after the initial scoping, planning, and Certificate of Need proceedings were complete for the Monticello EPU.[42] Retroactive cost caps fail to recognize shifting construction, regulatory, and industry environments, and are inconsistent with the standard that prudently incurred costs should be recoverable.

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[40] *See, e.g., Potomac Elec. Power Co. v. Pub. Serv. Comm'n of the Dist. of Columbia*, 661 A.2d 131, 141-42 (D.C. 1995); *Kansas Gas and Elec. Co. v. Stat. Corp. Comm'n*, 720 P.2d 1063, 1086 (Kan. 1986) (permitting utility to recover costs resulting from compliance with NRC safety requirements but disallowing specific imprudently incurred costs); *State ex. rel. Associated Nat. Gas Co. v. Pub. Serv. Comm'n of the State of Mo.*, 954 S.W.2d 520, 530 (Mo. Ct. App. 1997) (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers); *New England Power Co.*, 31 FERC 61,047 at 61,089 n.38 (2010) (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers).

[41] High level estimates have historically been recognized as appropriate for purposes of determining need, but also recognized as different than the level of information available at the cost recovery stage. Ex. 15, Alders Surrebuttal at 17:1-13.

[42] More recent Commission decisions have recognized the potential for tying certain recovery to initial estimates for certain types of new wind farm, transmission and natural gas projects. This discussion generally developed out of the Commission's 2010 Order with respect to the Company's Renewable Energy Standards (RES) Rider. *In re Petition of N. States. Power Co.*, Docket No. E-002/M-09-1083, ORDER APPROVING 2010 RES RIDER AND 2009 RES TRACKER REPORT, ESTABLISHING 2010 RES CHARGE, AND REQUIRING REVISED TARIFF at 5 (April 22, 2010). However, any additional costs are still recoverable, on a prospective basis, "upon a showing that it is reasonable to require ratepayers to pay for any such additional costs."

Further, there must be some causal connection between imprudent actions by the Company and harm to customers.[43] We are not suggesting that a proposed remedy must be tracked precisely to every avoidable dollar spent or every tool the Program purchased; rather, for a remedy to be supported in the record and reasonable, it must be tied to a reasonable estimate of avoidable costs and must balance the interests of both customers and the utility.

The OAG and XLI do not provide any correlation between avoidable costs and imprudence that can be supported on the record and instead resort to broader, encompassing remedies that effectively treat planning-level cost estimates as a sort of cap that begins the remedies-driven analysis. While we disagree with proxy remedies in general, the approach the Commission took in the Company's 2008 rate case, which is cited in the ALJ Report, at least was tailored to the harm identified.[44] Rather than disallowing broad portions of the Company's rate request because the specific cost resulting from known errors was difficult to calculate, the Commission tailored the remedy to the costs at issue. Likewise, the Company has provided specific costs tied to criticisms made by the Department's witnesses upon which the OAG and XLI rely.[45]

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[43] This principle is comparable to the negligence standard in that, even if imprudence is found, a cost disallowance is not permitted unless the imprudence is the real and proximate cause of injury. *See Pa. Pub. Util. Comm'n v. Duquesne Light Co.*, 63 Pa. P.U.C. 337, 352 (1987); *In re GPU, Inc.*, 96 Pa. P.U.C. 1, 91-92 (Jun. 20, 2001) ("Even if imprudence is found, a cost disallowance cannot be justified unless the utility's imprudent conduct was the real and proximate cause of some injury to customers."); *Pa. Pub. Util. Comm'n v. Philadelphia Elec. Co.*, 71 Pa. P.U.C. 42, 45-46 (Pa. P.U.C. 1989).

[44] Report at 36 (citing *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E-002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 20-21 (Oct. 23, 2009)).

[45] For example, the Department suggested that change orders resulted from poor planning; while we disagreed, we provided the amount of change orders the Company made. Xcel Energy Exceptions at 87 (citing Ex. 9, O'Connor Rebuttal). Where the parties characterized changing contractors or poor management as resulting in potentially duplicative design, we again provided the amount of cost associated with work on alternative design scenarios and abandoned work. Xcel Energy Exceptions at 87 (citing Ex. 9, O'Connor Rebuttal). We also addressed areas – such as the Company's initial cost estimate – that would not have

Below we provide additional discussion explaining why the OAG and XLI remedies are calculated improperly, are not consistent with the prudent investment standard, and are not appropriately tailored to the perceived harm they seek to remedy.

A. OAG Remedy

The OAG's proposed remedy relies largely on the assumption that all or most cost increases were due to poor management.[46] However, the OAG's proposed remedy would disallow cost recovery of an amount greater than the total cost increases for the entire Program. In addition, the OAG improperly calculates the costs it recommends for disallowance (including the amounts the ALJ used as Finding 109 and Conclusion 8 in the Report) and does not support others. Finally, the OAG's proposed remedy is inconsistent with the prudence standard and a proper balancing of utility and customer interests. As such, the OAG's remedy is inaccurate and excessive.

First, although the theme of the OAG's case is the assumption that cost increases are attributable to imprudence, the OAG proposes disallowing more than the difference between our initial cost estimate as escalated with the comparable final Program cost. The OAG's Exceptions propose disallowing $261 million related to cost increases in the feedwater heaters and 13.8 kV distribution system implementation and unspecified installation costs,[47] *plus* $19.5 million for changes and abandoned efforts,[48] *plus* 10 percent of the remaining cost increases,[49] *plus* no return on any recovered cost increases.[50] Before getting to the 10 percent and no return adjustments, disallowances

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resulted in different costs or decisions if the Company had offered a different estimate. Xcel Energy Exceptions at 33-37 (citing multiple sources).

46 OAG Exceptions at 1.

47 OAG Exceptions at 7. As discussed in more detail below, the ALJ's finding regarding the $261 million is not supported by the OAG's original derivation of the number.

48 OAG Exceptions at 8.

49 OAG Exceptions at 9.

50 OAG Exceptions at 10.

of $261 million plus $19.5 million alone exceed the correctly calculated $266 million difference between expected and final Program capital costs (without AFUDC).

Second, as noted earlier the OAG's argument that a total Program cost increase of $428.1 million should be at risk (ALJ Finding No. 110) mixes apples and oranges. To arrive at the $428.1 million, OAG subtracted the low end of the Certificate of Need estimate of $320 million (stated in 2008) from the final Program costs in this case with AFUDC totaling $748 million. This approach not only mixes unescalated dollars and escalated dollars, as well as numbers with and without AFUDC – it assumes that all cost increases were imprudent regardless of the unavoidable factors (including the few the ALJ did acknowledge, such as the NRC fatigue rule) that contributed to the cost increases.

Third, the $261 million disallowance advocated by the OAG in its post-hearing briefs and Proposed Findings was adopted incorrectly in Conclusion 8 of the ALJ Report. While the ALJ states that "cost overruns for the feedwater heater, the 13.8 kV distribution system, and the installation costs totaling at least $261 million were caused by Xcel's imprudent management," the $261 million represents 100 percent of the installation cost increases for the entire Program.[51] And as the OAG acknowledged in its briefs[52] but fails to disclose in Exceptions, the total installation cost increases for the whole Program include a substantial portion of the 13.8 kV system and feedwater heater cost increases. Thus the $261 million is not, as the OAG Exceptions now characterize it,[53] some calculated amount that is tailored to specific

[51] Ex. 200, Lindell Rebuttal at 28:4-11.

[52] The OAG's briefs and proposed findings contained only the statement that "The cost overruns for the feedwater heater, the 13.8 kV distribution system, and the installation costs total at least $261.1 million, given that some costs from the 13.8 kV system and the feedwater heater overlap with the installation costs." OAG Initial Br. at 41 (repeated at OAG Proposed Findings at ¶ 81).

[53] "[T]he ALJ concluded that at least $261 million in costs related to the 13.8 kV distribution system, the feedwater heater, and the installation costs were unreasonable; for that reason, the ALJ found that they must be disallowed." OAG Exceptions at 6.

unnecessary cost overruns. Instead, it is a blunt conclusion that inaccurately attributes all installation cost increases to imprudence. Similarly, the additional 10 percent reduction for perceived mismanagement has no relation to any particular costs driven up by the perceived harm.

Fourth, the OAG's proposed remedy – based largely on ALJ Conclusion 8 – is directly contradicted in the record and the ALJ's own findings. As discussed above, the cost increases for the 13.8 kV distribution system and the feedwater heaters, or for installation in general, were not 100 percent avoidable or imprudently incurred; rather, the detailed record establishes these cost increases were not only necessary but also delivered value for customers. And even the ALJ acknowledged that industry changes like the fatigue rule drove up installation costs;[54] the problem is that neither the ALJ Report nor the OAG's preferred remedy acknowledge the full extent of these changes or take steps to measure their impact on installation costs.

Perhaps for this reason, the OAG has been less than clear in its briefing and Exceptions regarding its original basis for advocating for $261 million. The record evidence illustrates that the OAG's basis for seeking disallowance of 100 percent of installation costs was a misapprehension of Dr. Jacobs' direct testimony.[55] Dr. Jacobs argued that "lack of understanding of the scope of the LCM and EPU projects is clearly shown by comparing the original [installation cost estimate] of $27.5 million to the actual installation costs of $288.6 million."[56] Dr. Jacobs, the OAG, and the ALJ all ignored that the $27.5 million installation estimate provided by General Electric for a partial scope of work was never intended to represent the final installation costs, and

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54 Report at Findings of Fact ¶¶ 66-67.

55 Ex. 200, Lindell Rebuttal at 28:5-10 (*quoting* Ex. 305, Jacobs Direct at 16).

56 Ex. 305, Jacobs Direct at 16:12-15.

we always knew installation would be a larger part of the effort.[57] And while we disagree with the implication that we should have completed more detailed design work for our initial need-level cost estimates, this quotation shows only that the Company did not anticipate the level of cost increases necessary to deliver a well-functioning and reliable nuclear plant; it does not suggest that the Company didn't need to incur those cost increases or that 100 percent of them could have been anticipated. Rather than examining the need for the final costs, the OAG's advocacy for disallowance of $261.1 million in installation cost increases was based on this quotation.[58]

Finally, the OAG's rough-cut remedy ignores that our overall costs and cost increases were fully consistent with the issues faced by other utilities and that other regulatory commissions, such as the Florida Commission, concluded that cost increases were prudently incurred and recoverable given the circumstances faced at the time.[59] The record demonstrates that our experience at Monticello was consistent with that of several plants around the country taking on similar projects at similar times, that low initial cost estimates were developed before the nuclear world changed, and that the drivers of our cost increases were these industry-wide changes and emerging plant needs rather than imprudence.[60] As we move forward to keep our plants running through their license period, we will need to make future investments in this new world. A general disallowance of this magnitude, without specific facts supporting imprudence or resulting harm, would be contrary to the prudence standard and would

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[57] Ex. 9, O'Connor Rebuttal at 47:8-13.

[58] Ex. 27, Lindell Rebuttal at 28:10-11.

[59] Tr. Vol. III (Jacobs) at 105:2-5; *see* Ex. 12, Sparby Rebuttal at 33:10-13.

[60] Ex. 3, O'Connor Direct at 24 4-14 and 24:11 at Table 3.

signal the investment community that our nuclear programs do not have strong regulatory support in Minnesota.[61]

Overall, although the OAG recites the prudent investment standard, the remedy it proposes is contrary to that standard, presents a disallowance of very high dollar amounts that have no correlation to perceived harm, and has the independent problem of being incorrectly and unfairly calculated. This remedy further assumes that doubt alone justifies a disallowance exceeding the amount of the Program's cost increases and encompassing more than 40 percent of total Program costs. This cannot be the right outcome in this prudence investigation either as a matter of law or of sound regulatory policy. As such, the OAG remedy was appropriately rejected by the ALJ.

B. XLI Remedy

XLI takes a different although equally infirm approach in designing a proxy remedy for perceived mismanagement. XLI did not actively participate in the hearing, did not sponsor any witnesses, and did not cross-examine witnesses. Nevertheless, they propose a remedy based on the Department's analysis. XLI adopts an approach similar to the OAG's by assuming that because costs went up, all of those costs should be at risk and subject to a broad reduction of recovery. Finally, XLI's calculation of its proposed remedy, like OAG's, fails to utilize comparable numbers and therefore overstates both the amount of the Program cost increases and the size of the remedy.

To put the impact of the XLI's proposed remedy in perspective, denying a return on the costs in excess of $320 million results in a $25.796 million revenue requirement reduction (Minnesota Jurisdictional basis) beginning in 2015. This would result in a

[61] Ex. 12, Sparby Rebuttal at 33:5-10.

substantial disallowance compared to the $10.237 million revenue requirement reduction recommended by the Department. It presents a substantial impact to the Company, and suggests that any increase in anticipated costs for a project could be subject to no return regardless of the causes of the cost increase or the value of the overall project to customers. This outcome is not supported either by the evidence in the record or Minnesota law, and is not a remedy the Commission should support.

It is important to keep in mind that while XLI characterizes their remedy as "no return" rather than a "complete disallowance,"[62] no return on hundreds of millions of dollars of plant investment is in fact a substantial disallowance.

In the context of ratemaking by regulatory authorities, it is well established that public utilities have a constitutional right to earn a sufficient return.[63] It is further a fundamental tenet of regulatory ratemaking that an unreasonable rate of return on investment would result in an unconstitutional taking of the public utility's property without just compensation.[64] Thus the return on an investment is a real cost that the utility is typically entitled to earn under the regulatory compact.

Further, the United States Supreme Court has recognized that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks" and "sufficient to assure confidence in the

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[62] XLI Exceptions at 6.

[63] *See R.R. Comm'n Cases v. Farmers Loan & Trust Co.*, 116 U.S. 307 (1886); *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 307-08 (1989) "The guiding principle has been that the Constitution protects public utilities from being limited to a charge for their property serving the public which is so 'unjust' as to be confiscatory. . . . If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation and so violated the Fifth and Fourteenth Amendments."); *Covington & Lexington Turnpike Rd. Co. v. Sandford*, 164 U.S. 578, 597 (1896) (stating that a rate is too low if it is "so unjust as to destroy the value of [the] property for all the purposes for which it was acquired" and thereby "practically deprive[s] the owner of property without due process of law").

[64] *See Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 691 (1923).

financial integrity of the enterprise, so as to maintain its credit and to attract capital."[65] State regulators must consider the "broad public interests" when establishing a utility's allowed rate of return.[66] A utility is entitled to earn a rate of return "adequate, under efficient and economical management, to maintain and supports its credit."[67] As such, XLI's proposition that a return is not part of the Company's cost structure is inconsistent with long-standing law and fails to balance the utility's need for an adequate return. Denial of a return on $400 million would be punitive and unsupported by the record.

Rather, any disallowance should be narrowly tailored to any harm incurred and balance the financial health of the utility with the needs of customers. XLI tries to position its extreme remedy as the moderate outcome in this case.[68] However, it ignores that the Company deployed substantial capital years before cost recovery occurred and customers now have a valuable asset for the long run. Company investors likewise expect to earn a return on their investments on behalf of customers. And abandoning the question whether we were imprudent in order to argue and arguing that we failed to meet our burden that rates would be just and reasonable without at least suggesting which of our costs could have been avoided is inconsistent with law and sound public policy.

The same evidence that shows the Company was prudent with respect to making decisions about plant needs and project management, which is described only in part in our Exceptions and above in these Reply Exceptions, counsels against the kind of overbroad, unsustainable remedy the XLI supports. The record simply does not

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65 *Federal Power Comm'n v. Hope Gas Co.,* 320 U.S. 591, 603 (1944).

66 *Permian Basin Area Rate Case*, 390 U.S. 747, 791 (1986).

67 *In re Central Vermont Pub. Serv. Corp.*, Docket No. 5701/5724, 1994 WL 713817 at 84 (Ve. P.S.B. Oct. 31, 1994) (citing *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923)).

68 XLI Exceptions at 6.

support findings of imprudence and denial of any return with respect to the entire increase above initial cost estimates – especially given that those cost estimates were known to be high level at the time they were offered, and that plant needs and industry changes played a tremendous role in driving cost increases. The XLI's remedy is, in fact, a broad disallowance, excessive, and suffers from the same faults as the OAG's approach. As such, both the OAG's and XLI's approach and the amounts of their proposed remedies were appropriately rejected by the ALJ.

V. CONCLUSION

For the reasons set forth above and in our Exceptions, the Company respectfully requests that the Commission adopt the ALJ Report with the changes described in our Exceptions and Attachment A to that document.

Dated: February 17, 2015

Respectfully submitted,

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ATTORNEYS FOR NORTHERN STATES POWER COMPANY

Xcel Energy
Reply to Exceptions
Attachment A – Discussion of Costs and Cost Increases

In the body of our Reply to Exceptions, the Company provides an analysis of the 13.8 kV distribution system and Feedwater Heaters modifications explaining why and how costs increased and that the OAG's and XLI's assumption that those cost increases were imprudent is incorrect. To further illustrate our prudence and the impropriety of sweeping remedies based on doubts, this Attachment provides similar analyses for the other cost drivers for the initiative, namely the reactor feed pumps and motors and condensate demineralizer modifications and NRC licensing costs. We also provide a summary of the work we did on the other modifications, including the turbine, steam dryer, condensate pumps and motors, transformers, and power range neutron monitoring system (PRNM). We provide these analyses to illustrate the complexity of the Program, our detailed decision processes, and the specific causes of cost increases that do not warrant the remedies advocated for by the OAG and XLI.

1. Reactor Feed Pumps and Motors

The existing reactor feed pumps and motors were original Plant equipment.[1] They were actually modified three-stage fire pumps (rather than two-stage pumps) that had been a perpetual source of operation and maintenance concerns.[2] These pumps and their motors had been identified as early as 2001 for replacement should Monticello extend its operating license from 2010 to 2030.[3] Specifically, around the time the uprate was initially investigated, the reactor feed pumps and motors had been

[1] Ex. 3, O'Connor Direct at 124:9-11; Ex. 9, O'Connor Rebuttal at 110:5-7.

[2] Ex. 9, O'Connor Rebuttal at 109:23-110:2.

[3] Ex. 9, O'Connor Rebuttal at 109:9-13 and Schedule 33.

identified for replacement within the next six years.[4] Thus when it came time to design the uprate, the idea of replacing this legacy equipment was well understood.

The initial 2006 analysis for EPU conditions at Monticello identified that additional reactor feedwater flow would be necessary. To achieve this increased flow, the initial option considered was the addition of a third, supplemental feed pump.[5] This configuration, estimated to cost approximately $27.8 million,[6] is what was included in the initial $274 million cost estimate.[7] As the LCM/EPU Program team began detailed evaluation of the Scoping Assessment, the supplemental reactor feed pump was identified for further analysis.[8]

The addition of a supplemental reactor feed pump and motor presented concerns with Plant operating procedures and size limitations.[9] Going from two to three pumps would have required sophisticated procedure changes that would have required retraining our NRC-licensed nuclear operators, which raised a significant concern with the Plant which places a premium on consistency and predictability.[10]

Based on all this information from the site projects team, the LCM/EPU Program Team recommended that the Site Steering Committee approve replacing the existing

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[4] Ex. 9, O'Connor Rebuttal at 109:19-21.

[5] Ex. 3, O'Connor Direct at 123:22-27.

[6] Ex. 3, O'Connor Direct at Schedule 26 at 1. This is the full amount allocated to the reactor feed pumps and motors modification at the time of the $320 million estimate (with a $346 million sensitivity) were provided with the 2008 Certificate of Need application, including the modification's proper share of estimated common costs.

[7] Ex. 9, O'Connor Rebuttal at Schedule 26 at 1 (Reactor Feed Pumps and Motors Summary).

[8] Ex. 9, O'Connor Rebuttal at Schedule 24 at 15 and 18.

[9] Ex. 9, O'Connor Rebuttal at 124:8-9.

[10] Ex. 4, Stall Direct at 48:10-49:5; 49:21-50:19; 52:1-54:6.

reactor feed pumps and motors with slightly larger equipment to primarily fulfill the LCM needs of the Plant but also support the EPU.[11]

The decision to proceed with the "two-pump solution" increased the cost of the modification to approximately double the initial estimate for the supplemental pump.[12] This replacement allowed the Plant to remove the modified fire pumps and install new pumps with motors that included more sophisticated monitoring equipment to allow the Plant to better provide operational data to the operators.[13] To accomplish the work necessary for the reactor feed pumps and motors to operate through the extended life of the Plant, the initial scope and the final scope are summarized in Table 1.

[11] Ex. 9, O'Connor Rebuttal at Schedule 24 at 15.

[12] Ex. 3, O'Connor Direct at Schedule 8 at 2. The estimated cost of the reactor feed pump and motor modification increased from $9.8 million (without allocated common) to $17.3 million (without allocated comment) between the supplemental reactor feed pump initial estimate and the decision to replace the reactor feed pumps and motors.

[13] Ex. 3, O'Connor Direct at Schedule 26 at 1 ("Final Scope").

Table 1. Reactor Feed Pumps and Motors Scope Summary[14]

Initial Scope ($27.8 million)	Final Scope ($92.2 million)
• Supplemental reactor feed pump • Supplemental reactor feed pump motor • Testing	• Replace two pumps and motors, including new foundations • Replace discharge piping with larger diameter piping • Install four five-ton jib cranes for installation and maintenance • Replace feedwater regulating valves and controls • Relocate emergency service water lines • Replace minimum flow valves • Replace auxiliary instrumentation • Demolition of existing equipment in the reactor feed pump and motor room • Relocation of area cooling • Installation of two-story installation scaffolding to make best use of outage time and craft labor resources[15] • Modifications and replacements to vent, drain, bypass, hydrogen injection, pump warm-up, and service water piping • Testing

The final cost of the modification, broken down into Design/Engineering, Materials/Components, Installation, Common, and General Costs is provided in Table 2.

[14] Ex. 3, O'Connor Direct at Schedule 26 at 1 and 2 (Reactor Feed Pumps and Motors Summary).

[15] Ex. 3, O'Connor Direct at 125:11-15.

Table 2. Reactor Feed Pumps and Motors Modification Cost by Category (Million $)[16]

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

* Child Work Order 11286955 MNGP EPU Replacement FW Pump

The final cost for the modification exceeded the initial estimate by approximately $64 million.[17] The primary driver for the increase in cost was the decision to proceed with the two-pump solution instead of installing a supplemental reactor feed pump and motor and delaying reactor feed pumps and motors replacement until a later time, which was estimated to be required by 2013 even without the EPU.[18] As a result of this decision, installation costs increased commensurate with the work necessary to complete the modification.[19] Additional costs were also incurred in final installation testing due to the evolution of regulatory expectations and industry experience in similar work from the time the modification was initially scoped and 2013.[20]

The Company was able to save approximately $6.6 million on this modification by rejecting the initially-proposed design that would have required rerouting over 290 feet of piping and developing a new design that only required rerouting 60 feet of lesser-diameter pipe.[21] Craft labor resources were maximized by constructing a two-

[16] Ex. 3, O'Connor Direct at 125:1 at Table 21. "Common" represents the allocated portion of the $103 million of Work Order 10435578.

[17] Ex. 3, O'Connor Direct at Schedule 26 at 1-2 (Reactor Feed Pumps and Motors Summary).

[18] Ex. 3, O'Connor Direct at 125:7-11; Ex. 9, O'Connor Rebuttal at 109:19-21.

[19] Ex. 3, O'Connor Direct at Schedule 26 at 2 (Reactor Feed Pumps and Motors Summary).

[20] Ex. 3, O'Connor Direct at Schedule 26 at 1 (Reactor Feed Pumps and Motors Summary).

[21] Ex. 9, O'Connor Rebuttal at 63:1-8.

story work area in the reactor feed pumps and motors room so that work could occur concurrently on the pumps an motors during the 2013 outage.[22]

Even with this concurrent work configuration, the work hour estimates developed by Bechtel for the 2013 outage replacement of the pumps and motors, which was based on the approved final engineering package, were underestimated by 35,000 hours and the installation exceeded estimates by approximately 40 days.[23] However, the work that was performed to replace the reactor feed pumps and motors was necessary to support the life extension of the Plant, with a small additional cost to accommodate the increased EPU flow conditions, and the Company identified ways to save money and maximize resources during the implementation of the modification.[24]

The reactor feed pumps and motors modification cost $92 million compared to the initial estimate of almost $28 million. While that cost increase was substantial, it was not imprudent. As the above discussion makes clear, the Company was diligent in identifying the upgrades that were necessary to serve the Plant's interests and worked hard to pick viable and reasonable alternatives. In particular, the choice of the two-pump solution served the Plant's interests well by minimizing the amount of disruption for our NRC-licensed operators. Further, the original pumps needed to be replaced in the next few years so advancing the work to coincide with the Program completed work that had to be done. Ultimately, while the costs were high, they were prudently incurred and unavoidable.

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[22] Ex. 3, O'Connor Direct at 125:11-15.

[23] Ex. 3, O'Connor Direct at Schedule 26 at 2 (Reactor Feed Pumps and Motors Summary).

[24] Ex. 3, O'Connor Direct at 126:9-14 and Schedule 26 (Reactor Feed Pumps and Motors Summary); Ex. 9, O'Connor Rebuttal at 63:1-8.

2. Condensate Demineralizer System

The initial cost estimate was premised on the assumption that the Company could simply replace the tanks (vessels) and make other improvements to the existing condensate demineralizer system rather than replace the controls.[25] As the Company progressed through initial design it became apparent that a full replacement of the system was needed because the existing system would not support long-term operations or the increased flow requirements at EPU levels.[26] In addition to addressing the equipment itself, it became clear the old analog control system needed to be upgraded to digital equipment. Further, the preexisting conditions that would emerge and cause significant operability and performance concerns were not fully appreciated in the Program's early stages.[27] Table 3 provides a comparison of the scope of work from the initial cost estimate to the final scope for this modification.

[25] Ex. 3, O'Connor Direct at 18:24-19:2.

[26] Ex. 3, O'Connor Direct at 107:12-14.

[27] Ex. 3, O'Connor Direct at 105: 14-15.

Table 3. Condensate Demineralizer Scope Summary[28]

Initial Scope ($18.0 million)	Final Scope ($79.8 million)
• Replace five vessels with 78-inch diameter vessels designed for 70-inch elements (removal and installation costs – not including costs for floor shield plugs). • Upgrade pre-coat pumps. • Modify analog control system. • Vessel disposal to be done by Company. • Testing	• Replace five vessels with 78-inch diameter vessels designed for 70-inch elements. • Relocate pre-coat skid. • Modify the tank vent system (T-33). • Add new air surge piping and larger capacity air surge tanks. • Modify holding pump design and backwash system. • Replace control panel with a digital, redundant, PLC system and add local motor control center. • Replace wiring and piping. • Install larger capacity holding pumps. • Install larger capacity resin traps. • Install larger capacity air surge and vent system. • Install air-operated valves. • Replace actuator for the condensate demineralizer bypass valve. • Testing

There were three primary factors that drove our costs for this modification. First, as discussed above, the scope of this project increased from replacement of five condensate demineralizer vessels and filter elements to a replacement of the entire system. For instance, in the initial cost estimate assumed replacement of the existing analog control panel at a cost of $96,000.[29] Ultimately, the Company decided to replace this analog system with automated, digital controls to reduce our reliance on

[28] Ex. 3, O'Connor Direct at Schedule 23 (Condensate Demineralizer Summary).

[29] Ex. 3, O'Connor Direct at Schedule 23 (Condensate Demineralizer Summary).

individual operators to consistently run the condensate system and thus, improve safety and reliability.[30] This digital system increased costs to $1 million.[31]

Second, due to the space limitations and high radiological environment of the vessel vaults, the necessary design effort was substantially greater than anticipated. The primary issue with the design efforts was the complexity of piping interferences and the condition of system wiring that was not discovered until demolition of the existing system, as well as the discovery of the backwash receiving tank design issue that required expedited design changes in the months before the 2011 outage.[32] For example, this modification necessitated in-outage design work to address various piping and instrumentation issues discovered after the tanks and vaults were exposed.[33] The piping configuration of the condensate demineralizer system did not entirely match the as-built drawings and these systems were not accessible during Plant operations.[34] In addition, shortly before the 2011 outage began, the Company discovered that the backwash tank was designed as an atmospheric tank and was insufficient to withstand overpressure of the backwash process.[35] Continuing with use of an atmospheric tank in this system would have presented significant risk of system failure, resulting in sudden release of contaminated water and resin from the backwash receiving tank.[36] As a result, the Company simultaneously began the

[30] Ex. 3, O'Connor Direct at 112: 25-27.

[31] Ex. 3, O'Connor Direct at Schedule 23 (Condensate Demineralizer Summary).

[32] Ex. 3, O'Connor Direct at 108:23-109:3.

[33] Ex. 3, O'Connor Direct at Schedule 23 (Condensate Demineralizer Summary).

[34] Ex. 3, O'Connor Direct at 110:7-9.

[35] Ex. 3, O'Connor Direct at 109: 5-7.

[36] Ex. 3, O'Connor Direct at 109:8-11.

constructability and re-design of this modification in the months before the 2011 outage.[37]

Finally, space limitations and the high radiological environment also led to increased implementation costs.[38] Installation costs for the system were impacted by the fact that the condensate demineralizer vessels are located in a vault with concrete walls.[39] The walls were poured after the original vessels had been installed.[40] While the Company understood the environment craft labor would be working in, efforts to replace the system required performance of substantial work in a radioactive and extremely confined space.[41] Due to these spatial limitations, only two people could work in a vault at one time and due to the radiological work environment, laborers were required to comply with work permit restriction, personal protective equipment, and step off protocols.[42]

The Company incurred approximately $79.8 million to complete the condensate demineralizer system modification.[43] Approximately $28.2 million, or 35 percent, of the costs for design and engineering services and approximately $32.1 million, or 40 percent, for installation of this modification.[44] Table 4 provides the final cost of the condensate demineralizer project by major cost category.

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37 Ex. 3, O'Connor Direct at 109:11-13.

38 Ex. 3, O'Connor Direct 109:15-18.

39 Ex. 3, O'Connor Direct at 33:8-9.

40 Ex. 3, O'Connor Direct at 33:9-10.

41 Ex. 3, O'Connor Direct at 33:10-11.

42 Ex. 3, O'Connor Direct at 109:25-110:2.

43 Ex. 3, O'Connor Direct at 107:20-21.

44 Ex. 3, O'Connor Direct at 107:21-24.

Table 4. Condensate Demineralizer System Cost by Category (Million $)[45]

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

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

The condensate demineralizer modification cost nearly $80 million compared to the initial estimate of almost $20 million. As the above discussion makes clear, replacing this legacy system was necessary to support long-term operations of the plant. Many of the cost increases were unforeseeable as they were related to (i) unforeseen interferences that came to light during installation, (ii) degraded wiring and other equipment that could not be known when we began work, and (iii) higher labor costs due to installations in highly radiological environments.

3. Licensing

The Company's initial estimate for licensing costs was about $28.6 million and was estimated to take less than two years.[46] The Company's licensing costs totaled approximately $59.3 million at the time of our initial filing with an additional $5 million related to ascension.[47] The licensing effort ended up taking five years and included a significant amount of additional analysis and faced numerous issues that were unique and unforeseeable. Table 5 provides a comparison of the initial scope of work from the initial 2008 cost estimate to the final scope and actual licensing cost.

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45 Ex. 3, O'Connor Direct at Table 18.

46 Ex. 3, O'Connor Direct at 136:18-19.

47 Ex. 3, O'Connor Direct at 136:16-18.

Table 5. Licensing Scope Summary[48]

Initial Scope ($28.6 million)	Final Scope ($59.5 million)
• Estimate only prepared for minimal vendor involvement for EPU and MELLLA+ licensing.	• License amendment request for EPU and MELLLA+ included General Electric cost based on issuance of final contract, internal costs, and NRC fees for review.

The following factors contributed to the increase in the Company's licensing costs for the Program: 1) the evolving nature of NRC oversight that occurred beginning in 2008 significantly contributed to the increase in cost and time; 2) increased NRC scrutiny over calculations, including the effort around the Containment Accident Pressure (CAP) credit issue; and 3) replacement steam dryer review.[49]

First, the Company's initial licensing cost estimate of $28.6 million was based on the Company's prior experience with the 1998 uprate project and General Electric's prior experience.[50] Based on this prior experience, the Company assumed that about half of these costs would be incurred through General Electric and roughly half would be internal and other contractor costs.[51] After 2008 when we filed our license amendment request, the NRC regulatory environment changed significantly. Under the new and evolving regime, there was need to complete additional calculations to respond to the NRC's requests. As a result of changing NRC requirements, the number of calculations required for the LCM/EPU Program was dramatically greater than the number of calculations required for the 1998 uprate.[52]

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[48] Ex. 3, O'Connor Direct at Schedule 17 (Licensing Summary).

[49] Ex. 3, O'Connor Direct at 137:3-7.

[50] Ex. 3, O'Connor Direct at 137:12-14.

[51] Ex. 3, O'Connor Direct at 137:14-16.

[52] Ex. 3, O'Connor Direct at 137:25-138:2.

The Company estimates that the additional calculations required by the NRC increased costs by $16 million.[53] In addition, the increased scrutiny by the NRC over the course of the Program meant that the Company received and responded to more than 460 Requests for Additional Information (RAIs) pertaining to the EPU and Maximum Extended Load Line Limit Analysis (MELLLA+) license amendment requests.[54] Responding to these RAIs also increased costs.

Second, the Company's licensing costs were impacted by the CAP issue. Monticello was approved to use CAP credit under its license basis and the Company used these requirements in its 2008 submission to the NRC.[55] This approach was consistent with the approach of other utilities seeking EPU approval and CAP credit granted by the NRC in earlier EPU license amendments.[56] Shortly after the Company submitted the license amendment request in November 2008, the Company's CAP methodology was challenged by the ACRS and others.[57] Ultimately, the NRC approved our CAP analysis in 2013, marking the first time the industry has successfully addressed the CAP issue under the new NRC guidelines.[58] In the end, the CAP issue delayed NRC approval of the Company's licensing process by approximately four years and added direct costs of at least $1 million to the Program.[59]

Third, additional licensing costs were incurred due to the NRC's lengthy review of the structural analysis of the new steam dryer. As a result of the NRC's review, the

53 Ex. 3, O'Connor Direct at Schedule 17 (Licensing Summary).

54 Ex. 9, O'Connor Rebuttal at 25:17-19.

55 Ex. 9, O'Connor Rebuttal at 28:15-16.

56 Ex. 9, O'Connor Rebuttal at 28:18-20.

57 Ex. 9, O'Connor Rebuttal at 29:3-5.

58 Ex. 9, O'Connor Rebuttal at 30:18-20.

59 Ex. 9, O'Connor Rebuttal at 31:2-4.

Company made repairs to strain gauges used to monitor steam dryer loads and accelerometers used to monitor piping vibration for inaccessible piping that resulted in costs of approximately $1.2 million.[60] Removal of steam dryer instrumentation to allow refueling activities to progress increased cost by roughly $1 million.[61]

Finally, the review of the specifications for the new steam dryer resulted in significant additional analysis and licensing costs.[62] The NRC asked the Company to provide six separate analyses of the steam dryer.[63] Each one of these analyses required considerable effort by both internal and external resources.[64] The Company estimates that the re-analysis of the steam dryer and the second EPU license amendment request submittal increased costs by $4.5 million.[65] Table 6 provides a summary of the costs by the applicable child work order for licensing activities.

Table 6. Licensing Cost by Category[66]

	Work Order	2011	2012	2013	Total
11536446	MNGP EPU License Development	50,015,888	(11,323,392)	4,658,214	43,350,710
11636097	EPU Lic-HELB Design Basis Documents	-	4,906,024	(127,515)	4,778,509
11636101	EPU Lic-Envir Qual DBD	-	2,558,596	(36,360)	2,522,236
11636105	EPU Lic-HELB & Inst Srv DBD	-	2,175,334	(30,892)	2,144,441
11636109	EPU Lic- Motor & Air Op Vlv Sys Design Basis Docs	-	2,619,272	(36,835)	2,582,437
11636114	EPU Lic- Piping Stress Design Basis Documents	-	4,111,340	(58,610)	4,052,730
11775097	EPU MELLA+	-	-	52,028	52,028
	Total:	**$ 50,015,888**	**$ 5,047,175**	**$ 4,420,030**	**$ 59,483,092**

[60] Ex. 3, O'Connor Direct at Schedule 17 (Licensing Summary).

[61] Ex. 3, O'Connor Direct at Schedule 17 (Licensing Summary).

[62] Ex. 3, O'Connor Direct at 139:12-13.

[63] Ex. 3, O'Connor Direct at 139:13-14.

[64] Ex. 3, O'Connor Direct at 139:14-15.

[65] Ex. 9, O'Connor Rebuttal at Table 2.

[66] Ex. 3, O'Connor Direct at Schedule 17 at 2 (Licensing Summary).

4. Other Major Modifications

The remaining major modifications (turbine, steam dryer, PRNM, transformers, and condensate pumps and motors) account for an increase of $32.6 million over the initial 2008 estimates.[67] It is noteworthy that these installations were generally more in the nature of replacing discrete pieces of equipment with similar pieces of equipment. As such, these replacements were generally less complicated and less expensive than the major construction projects that contributed to most of our cost increases.

These increases, and the scope changes for these modifications, are summarized in Table 7.

[67] Ex. 3, O'Connor Direct at Schedules 19 (Turbine Summary), 21 (PRNM Summary), 22 (Steam Dryer Summary), 24 (Transformers Summary), and 27 (Condensate Pumps and Motors Summary).

Table 7. Other Modifications Initial Scope and Final Scope Summary[68]

Modification	Initial Cost	Initial Scope	Final Cost	Final Scope
Turbine	$60.2 million	• Replacement of high-pressure turbine • State 8 and 10 replacement of low-pressure turbine • Replace cams in camshaft • Turbine generator Bentley Nevada Vibration Monitoring system • Testing	$57.5 million ($2.7 million under estimate)	• Replacement of high-pressure turbine • State 8 and 10 replacement of low-pressure turbine • Replace cams in camshaft • Turbine generator Bentley Nevada Vibration Monitoring system • Testing
Steam Dryer	$35.9 million	• Replace steam dryer • Replace instrumentation • Testing	$37.7 million ($1.8 million over estimate)	• Replace steam dryer • Replace instrumentation • Evaluation of contingency modifications and evaluations • Installation of cabling to support the new instrumentation system • Testing
PRNM	$15.7 million	• PRNM installation • Testing	$17.5 million ($1.8 million over estimate)	• PRNM installation • Upgrade of the process computer • Testing
Transformers	$16.9 million	• Replace main transformer • Replace 1AR transformer • Testing	$29.9 million ($13 million over estimate)	• Replace main transformer • Replace 1AR transformer • Install main transformer fire detection and suppression • Prepare old main transformer as spare for Plant • Testing
Condensate Pumps and Motors	$3.2 million	• Replace condensate pump internals • Replace condensate pump motors • Testing	$21.9 million ($18.7 million over estimate)	• Replace condensate pump (not just internals) • Replace condensate pump motors • Replace condensate pumps and motors auxiliaries • Replace area HVAC • Increase condenser hotwell level • Testing

[68] Ex. 3, O'Connor Direct at Schedules 19 (Turbine Summary), 21 (PRNM Summary), 22 (Steam Dryer Summary), 24 (Transformers Summary), and 27 (Condensate Pumps and Motors Summary).

These modifications total $164 million of the final $665 million for the Program.[69]

The turbine modification went well with all necessary equipment installed and all components replaced for $2.7 million less than the initial estimate.[70] Table 8 provides a summary of the initial estimate, the final cost, and the modification changes that affected the final cost.

Table 8. Turbine Modification Cost Summary[71]

Initial Turbine Estimate	Additions/Subtractions	Final Cost
$60.2 million	- $2.7 million for fabrication and installation savings	$57.7 million

Cost savings were achieved primarily through savings on installation and testing.[72] Even though there were unexpected in-outage delays for this modification, it still came in with final costs less than the budgeted amount.[73]

The PRNM and steam dryer modifications were each implemented with final costs only $1.8 million more than the initial estimates.[74] The PRNM required replacement because the Plant's old average power neutron monitor and oscillation power range monitor systems were aged and presented obsolescence and spare parts issues.[75] The cost for the PRNM modification increased $1.8 million from initial estimates primarily because of the decision to upgrade the Plant process computer to a state-of-the-art

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69 Ex. 3, O'Connor Direct at Schedules 19 (Turbine Summary), 21 (PRNM Summary), 22 (Steam Dryer Summary), 24 (Transformers Summary), and 27 (Condensate Pumps and Motors Summary).

70 Ex. 3, O'Connor Direct at Schedule 19 at 1 (Turbine Summary).

71 Ex. 3, O'Connor Direct at Schedule 19 at 1 (Turbine Summary).

72 Ex. 3, O'Connor Direct at Schedule 19 at 1 (Turbine Summary).

73 Ex. 3, O'Connor Direct at Schedule 19 at 1 (Turbine Summary).

74 Ex. 3, O'Connor Direct at Schedule 21 at 1 (PRNM Summary) and Schedule 22 at 1 (Steam Dryer Summary).

75 Ex. 3, O'Connor Direct at 99:26-100:2.

processing system that would alleviate the need to continually test and monitor the average power neutron monitor system.[76] Additionally, installation of the PRNM incurred approximately $200,000 because of the required separate license amendment request to the NRC.[77] Finally, costs increased slightly because of pre-operational and modification acceptance tests which resulted in the PRNM being brought online with no start-up issues, something no other nuclear plant in the United States has done.[78] Table 9 provides a summary of the costs incurred in excess of the initial estimate for the PRNM modification.

Table 9. PRNM Modification Cost Summary[79]

Initial PRNM Estimate	Additions/Subtractions	Final Cost
$15.7 million	+ $0.2 million for separate license amendment request + $1.6 million for new processing system and additional pre-operational testing	$17.5 million

The steam dryer required replacement because the original steam dryer, designed in the mid-1960s, had experienced decreased operability and the moisture carryover was marginally acceptable at the time the Program was initiated.[80] The Company initially believed that these concerns could be addressed through modifications to the existing dryer but further analysis made it apparent that replacement of the steam dryer was necessary to support the 20-year extended operation of Monticello.[81] At the time the initial estimate for the Program was developed for the 2008 Certificate of Need

[76] Ex. 3, O'Connor Direct at 100:3-6.

[77] Ex. 3, O'Connor Direct at Schedule 21 at 1 (PRNM Summary).

[78] Ex. 3, O'Connor Direct at 101:11-13.

[79] Ex. 3, O'Connor Direct at Schedule 21 at 1 (PRNM Summary).

[80] Ex. 3, O'Connor Direct at 103:6-8; Ex. 305, Jacobs Direct at 11:4-6.

[81] Ex. 3, O'Connor Direct at 103:13-104:4.

application, the steam dryer modification was estimated to cost $35.9 million.[82] The final costs increased by $1.8 million over this estimate primarily because of the installation of sophisticated acoustic monitoring instrumentation installed in response to the NRC's concerns over steam dryer failures at nuclear facilities.[83] The information gathered from this monitoring equipment will be used to avoid similar incidents at our facility and other nuclear facilities.[84] Table 10 provides a summary of the costs incurred for the steam dryer modification from the initial estimate to the final cost.

Table 10. Steam Dryer Modification Cost Summary[85]

Initial Steam Dryer Estimate	Additions/Subtractions	Final Cost
$35.9 million	+ 1.8 million for installation of acoustic monitoring equipment and analysis of outputs	$37.7 million

The transformer replacements modification required the replacement of the main power transformer and the 1AR emergency transformer.[86] The 1AR was not new equipment when it was acquired for use at Monticello and, by the time it was replaced as part of the Program, was approximately 60 years old – making it one of the oldest transformers still in service in the United States nuclear fleet.[87] The main power transformer was approximately 40 years old and operating experience within the nuclear industry suggested the transformer was near the end of its useful life.[88] The primary drivers for the $13 million increase in modification costs can be attributed to

[82] Ex. 3, O'Connor Direct at Schedule 22 at 1 (Steam Dryer Summary).

[83] Ex. 3, O'Connor Direct at 104:22-105:1.

[84] Ex. 3, O'Connor Direct at 105:1-2.

[85] Ex. 3, O'Connor Direct at 104:22-24 and Schedule 22 at 1 (Steam Dryer Summary).

[86] Ex. 3, O'Connor Direct at 113:6-8.

[87] Ex. 3, O'Connor Direct at 115:5-9; Ex. 9, O'Connor Rebuttal at 114:9-12.

[88] Ex. 3, O'Connor Direct at 114:24-27.

the installation of fire protection equipment and isophase bus duct cooling, the cost to refurbish the existing main power transformer and construct on-site storage, and the escalation of commodity price from initial estimates to procurement.[89] The Company was able to avoid additional costs for this modification by requiring the vendor to cover costs associated with issues encountered in the fabrication and delivery of the components.[90] A summary of costs for this modification is provided in Table 11.

Table 11. Transformer Replacement Modification Cost Summary[91]

Initial Transformer Replacement Estimate	Additions/Subtractions	Final Cost
$16.9 million	+ $4.1 million in additional costs to procure materials[92] + $8.9 million to design and install the main transformer fire detection and suppression system,[93] to design and install the isophase bus duct cooling, to design and implement the refurbishment of the old main transformer, and to design and construct the spare transformer storage.[94]	$29.9 million

[89] Ex. 3, O'Connor Direct at 115:23-7.

[90] Ex. 3, O'Connor Direct at 116:11-17.

[91] Ex. 3, O'Connor Direct at Schedule 24 at 1-2 (Transformer Summary).

[92] Ex. 3, O'Connor Direct at Schedule 24 at 1 (Transformer Summary). The initial estimate included $4.5 million for a new main transformer and $3.5 million for a new 1AR transformer with the final materials cost of $12.1 million. These materials include the fire detection and suppression equipment, isophase bus duct cooling, and materials necessary for the refurbishment, but do not include any design, engineering, or installation costs for these components.

[93] The installation of a main power transformer fire suppression system was required by the Plant's insurance carrier. Ex. 3, O'Connor Direct at 114:18-19.

[94] If a main power transformer at a plant fails, the plant remains offline until the transformer can be replaced or repaired, which can take a long period of time. Ex. 3, O'Connor Direct at 114:26-115:1. The refurbished main power transformer remains onsite to provide the station with a transformer in the event the installed transformer experiences operational issues and allowed Monticello to save costs by not acquiring a new spare main power transformer as recommended under best practices. Ex. 3, O'Connor Direct at 114:11-16.

Initially, the Company intended to replace the condensate motors and only the internals of the pumps.[95] The condensate motors were original Plant equipment and the performance of the pump/motor combinations was degrading to a point where adequate suction flow/pressure could not be provided to the reactor feed pumps.[96] After further evaluation, the Company determined that replacement of both the condensate pumps and motors was necessary to meet the increased water demand of the reactor feed pumps.[97] The decision to replace the pumps instead of just the internals was the primary driver for the increased final cost.[98] Another cost driver for the modification was that the increased heat load of the motors required further analysis of the area cooling systems and design and installation of a new HVAC cooling system that added $2 million to the modification.[99] Although the need to install new HVAC cooling for the condensate motors resulted in an additional cost of $2 million, the implemented solution was $2.2 million less than the initial design presented for the increased motor head load.[100] Finally, additional costs for the condensate pumps and motors modification were incurred because of the need to increase the condenser hotwell level to achieve net positive suction head, to provide on-site personnel at the pump and motor fabricators to verify that all equipment met specifications, to replace pump and motor auxiliaries, and to address vibrations identified in pipe supports during installation.[101] Table 12 provides a summary of the costs for this modification.

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[95] Ex. 3, O'Connor Direct at 127:10-11 and Schedule 27 at 1 (Condensate Pumps and Motors Summary).

[96] Ex. 9, O'Connor Rebuttal at Schedule 32 at 10 (Company response to Department IR 124).

[97] Ex. 9, O'Connor Rebuttal at 110:25-111:26.

[98] Ex. 3, O'Connor Direct at 128:15-19 and Schedule 27 at 2 (Condensate Pumps and Motors Summary).

[99] Ex. 3, O'Connor Direct at 128:22-129:2 and Schedule 27 at 1-2 (Condensate Pumps and Motors Summary).

[100] Ex. 9, O'Connor Rebuttal at 63:12-17.

[101] Ex. 3, O'Connor Direct at 129:10-14 and Schedule 27 at 1-2 (Condensate Pumps and Motors Summary).

Table 12. Condensate Pumps and Motors Cost Summary[102]

Initial Condensate Pumps and Motors Estimate	Additions/Subtractions	Final Cost
$3.2 million	+ $10 million to replace pumps instead of internals + $2 million for HVAC cooling system + 6.7 million to increase hotwell level 0.5 feet, provide on-site monitoring at pump fabricators, replace pump and motor auxiliaries, design, engineering, and installation activities for pipe supports to resolve post-installation vibrations	$21.9 million

5. *Conclusion*

The work to implement the major modifications discussed in this Attachment was necessary for the continued operation of the Plant. Although the final costs were higher than the costs initially estimated, these increases can be attributed to the additional work that was identified as necessary after our initial scope for each modification was developed. Throughout the planning, design, and engineering process, the Company carefully evaluated the work that would be necessary to ensure that once each modification was complete, the Plant would operate as anticipated.

As demonstrated by the record and summarized in this Attachment, a broad disallowance is not warranted. The Company thoughtfully evaluated alternatives along the way through its design, engineering, and implementation of the Program and selected the alternative that was most appropriate for the given circumstances. Additionally, the Company identified areas where it could avoid additional costs by maximizing design and implementation resources. The Company's actions throughout the Program were appropriate and reasonable based on the information the Company knew or reasonably should have known at the time.

[102] Ex. 3, O'Connor Direct at Schedule 27 at 1-2 (Condensate Pumps and Motors Summary).

IN THE MATTER OF A COMMISSION INVESTIGATION INTO XCEL ENERGY'S MONTICELLO LIFE CYCLE MANAGEMENT/EXTENDED POWER UPRATE PROJECT AND REQUEST FOR RECOVERY OF COST OVERRUNS

MPUC DOCKET NO: E002/CI-13-754
OAH NO. 48-2500-31139

CERTIFICATE OF SERVICE

Jill N. Yeaman certifies that on the 17th day of February, 2015, she filed a true and correct copy of **XCEL ENERGY'S REPLY EXCEPTIONS** by posting the same on www.edockets.state.mn.us. Said document is also served via U.S. Mail or email as designated on the Official Service List on file with the Minnesota Public Utilities Commission in the above-referenced docket.

s/ Jill N. Yeaman
Jill N. Yeaman

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