Final Report

to the

Department of Commerce – Energy Division

of the

State of Minnesota

Independent Investigation of Cost Overruns

and

Cost Estimates for Xcel Energy's

Prairie Island Nuclear Power Plant

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SECTION 1.0: INTRODUCTION

Global Energy & Water Consulting, LLC. ("Global or Consultant") has been retained by the State of Minnesota's Department of Commerce, Division of Energy Resources ("Department") to investigate Northern States Power, d/b/a Xcel Energy's ("Xcel" or "Company") handling of costs for the Prairie Island Life Cycle Management ("LCM") and the Extended Power Uprate ("EPU") projects as the Company identified in the General Rate Case Docket No. E002/GR-15-826 ("Multi-Year Rate Case") and the 2015 Integrated Resource Plan in Docket No. E002/RP-15-21 ("2015 IRP"). Global's responsibility in this docket is to review the decisions, actions, and costs of Xcel during the LCM & EPU projects not in the context of the actual rate case but to substantiate the relationship between Xcel's decisions and how these decisions may have affected costs and schedules for both projects.

In the Multi-Year Rate Case, Xcel's request to increase rates included significant increases in capital and operation & maintenance ("O&M") costs above the (escalated) dollars that the Company identified and the Commission approved in Xcel's EPU and additional dry cask storage projects in Dockets E-002/CN-08-509 and E-002/CN-08-510, respectively.

Specifically, as the Department identified in Direct Testimony in the Multi-Year Rate Case, Xcel requested to recover costs that exceed the costs that Xcel represented in the CN petitions by the amounts shown in Table 1 below.[1]

In addition, the Company estimated in the 2015 IRP that Prairie Island's capital costs would exceed earlier estimates by $600 to $900 million between 2021 and 2034,[2] costs that would be in addition to the cost overruns proposed to be recovered in the Multi-Year Rate Case.

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[1] Cost overruns for the Prairie Island Nuclear Power Plant are discussed in the June 14, 2016 Direct Testimony of Ms. Nancy Campbell, Docket No. E-002/GR-15-826 in Xcel's Multi-Year Rate Case (MYRC), which is referenced in Table 1.

[2] Xcel's October 2, 2015 filing at 13, Docket No. E002/RP-15-21.

Table 1: Capital Costs Through 2020 Exceeding Amounts in Certificate of Need Proceedings (Total Company $)

	Prairie Island Excess Capital Costs	Monticello Excess Capital Costs[3]	Total
Spent Fuel	$38.13 million[4]	$36.48 million[5]	$74.61 million
Other Costs	$302.6 million[6]	$15.1 million[7]	$317.7 million
Total	$340.73 million	$51.58 million	$392.31 million

The Commission determined a need to engage a nuclear expert to provide an evaluation of Xcel's nuclear spending, focused on how the LCM & EPU process and the mandated compliance costs would impact Minnesota ratepayers. Specifically, in light of the cost increases identified in the Multi-Year Rate Case and in Xcel's 2015 IRP, the Commission's December 22, 2015 *Notice of and Order for Hearing* identified the following two-pronged issue to be developed for use in both Xcel's next IRP and the Company's next rate case:

> Whether, in light of the following factors, the amounts authorized for cost recovery in the 2016 test year and the 2017 and 2018 plan years should be considered provisional or placeholder amounts until the Commission makes a determination on the prudency of the Life Cycle Management costs at the Prairie Island plant:
>
> a) Xcel's pending submission of a Nuclear Scope Study in its January 29, 2016 supplemental comments in its resource plan, docket E-002/RP-15-21; and
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> b) The possibility that there will not be adequate time to fully investigate and determine the prudence of these costs in this rate case.

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[3] The capital cost overruns for Monticello are as follows: $15.1 million is due to Xcel failing to adequately supervise a contractor that was welding a nuclear waste storage cask, and $36.48 million is for other cost overruns for Monticello's life-cycle management compared to the amounts in E002/CN-05-123, for a total of $51.58 million. These cost overruns are in addition to the cost overruns from the extended power uprate for Monticello, which the Commission addressed in Docket E002/CI-13-754.

[4] Ms. Campbell MYRC Testimony, pages 80-83.

[5] Ms. Campbell MYRC Testimony, pages 77-80.

[6] Ms. Campbell MYRC Testimony, pages 83-96.

[7] Ms. Campbell MYRC Testimony, pages 71-77. Xcel failed to supervise properly the contractor that welded storage casks.

Thus, the Commission's April 15, 2016 *Order Asking Commissioner of Commerce to Seek Funding for Specialized Technical Professional Investigative Services Under Minn. Stat. § 216B.62, Subd. 8* determined that a thorough investigation of all projected Prairie Island costs was needed, along with specialized, technical assistance:

> The Commission concurs with the Department and the Company that thorough analysis of all projected Prairie Island costs is critical to a fair and reasonable outcome in both the resource-plan and rate-case dockets. In the resource-plan case, determining the probable level of these costs is critical to determining the most cost-effective resource mix for Xcel through 2034, including the most reasonable role in that mix for Sherco 1 and Sherco 2. In the general rate-case docket, determining the probable level, prudence, and reasonableness of these costs is critical to setting just and reasonable rates.

During the Multi-Year Rate Case, the Company, the Department, the Xcel Large Industrials, the Minnesota Chamber of Commerce, the Commercial Group, the Suburban Rate Authority, the City of Minneapolis, the Industrial, Commercial, and Institutional customer group, and the Energy CENTS coalition negotiated a *Stipulation of Settlement* ("Settlement") that resolved, for purposes of setting rates in that case, the questions of cost overruns with regards to the Prairie Island Nuclear O&M and Capital cost increases associated with the EPU, LCM and dry cask storage. However, as stated in the Commission's June 12, 2017 *Findings of Fact, Conclusions, and Order* (Multi-Year Rate Case Order), it is still necessary

> …to examine the continued cost-effectiveness of the Company's nuclear fleet and evaluate the Company's planned capital and operations and maintenance (O&M) expenses, with the understanding that Xcel will continue to carry the burden of demonstrating the reasonableness of future rate increases.

While the Settlement provided the basis for moving forward with the Multi-Year Rate Case, it did not preclude Xcel from requesting to recover the remaining balance (less accumulated depreciation) of costs that exceed the CN levels in a future rate proceeding.[8] Therefore, despite the Settlement, the Department along with others determined it to be

[8] Multi-Year Rate Case Order, page 12, which also identified that "At hearing, Xcel confirmed that the Settlement does not provide for deferral of Prairie Island costs that are not recovered through the rates set in this case."

appropriate for the specialized nuclear consultant to continue to review the overall cost overruns and decisions made by Xcel. (As discussed further below, Global Energy was retained in the fall of 2016 to accomplish the review of the Company's costs.)

The Global Team[9] assembled for this project has visited with the Department, Xcel personnel, visited Prairie Island twice (April 25, 2017 and May 22, 2018) for discussions with Xcel's operational and management personnel, submitted numerous Information Requests, reviewed extensive documentation provided by Xcel, as well as documentation that is included in dockets addressing rates and integrated resource planning ("IRP") from the 2008 period forward to this docket. Global's goal was to rebuild the decision-tree to resemble as closely as possible that of the Company at the time of their decisions to enter into the EPU/LCM and dry cask storage projects. This approach avoids 20/20 hindsight to reflect, as best possible, the knowledge and information available to the Company at the time decisions were made. However, on a going forward basis 20/20 hindsight on events to date could provide benefits for upcoming decisions.

This process and report is intended to emphasize the necessity for Xcel to fully inform the Minnesota Public Utilities Commission ("Commission"), charged with regulatory oversight, the Department, charged with ratepayer advocacy, and any other interested party about any material changes in the nuclear plants. The goal is to help ensure transparency with plans and decisions so that ratepayers can be provided with price-competitive energy, while the Company maintains stability within the market place, provides reliable and safe energy resources, and continues to be a reasonable value to stockholders.

[9] Discussion of the Global Team and Qualifications is included in the Appendix to this Report.

SECTION 2.0: PURPOSE AND APPROACH

Over time, the EPU project evidently evolved through several iterations, modifying the scope and increasing the cost above the levels in the approved CN applications. The result was a request in the Multi-Year Rate Case for significantly higher cost recovery through rates than was presented in the original CNs.

Xcel, as early as the 2004 time frame, initiated their IRP process studies to evaluate the extension of the Nuclear Regulatory Commission ("NRC") license for Prairie Island beyond the original lives of 2013 and 2014 for the two units. In order for Xcel to extend the life of Prairie Island and apply for license modifications it was necessary to submit to the NRC a License Amendment Request ("LAR" or License Extension).

In May of 2008, Xcel submitted its *Application to the Minnesota Public Utilities Commission for Certificate of Need for the Prairie Island Nuclear Generating Plant for Extended Power Uprate* (Docket No. E002/CN-08-509) and *Application to the Minnesota Public Utilities Commission for Certificate of Need for the Prairie Island Nuclear Generating Plant for Additional Dry Cask Fuel Storage* (Docket No. E002/CN-08-510). The EPU application was for the Company to uprate the capacity of the Prairie Island Units 1 & 2 by 164 MW. The dry cask storage was necessary in order to store additional fuel on site as there is yet to be developed a U.S. centralized storage facility for spent nuclear fuel as was planned for Yucca Mountain. Both of these projects were initiated to meet forecasted energy growth and to operate Prairie Island beyond its then-current license expiration dates of 2013 and 2014.

The Company submitted its LAR to the NRC in August of 2010. Leading up to the Application for the CN and the LAR, Xcel carried out various engineering studies and IRP evaluations in support of the two regulatory requirements. Xcel identified in its Multi-Year Rate Case that the capital costs during this permitting period and subsequent to the issuance of both the CN and the License Extension through 2016 exceeded $1.15 billion.[10] The forecast for

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[10] Capital Costs are from Company witness Scott L. Weatherby testimony dated January 29, 2016 in Docket No. E002/GR-15-826, Schedule 3, page 1 of 2, sum of figures in column "Annual Prairie Island Capital Spending" for the

capital spending for the Period 2016 – 2020, excluding fuel, exceeded $487 million,[11] excluding the mandatory compliance costs of another $214 million through 2015[12] and $89 million forecast through 2020.[13] This total capital expenditure of $790 million for 2016-2020 does not include labor, operation and maintenance or other costs and does not include any costs beyond 2020.

As discussed in Section 1.0 of this report, Xcel proposed to recover cost overruns from ratepayers in the Multi-Year Rate Case. Xcel requested recovery of costs associated with capital expenditures of $392.31 million more than the amounts in the CNs for both Prairie Island and Monticello, escalated to current dollars, as indicated in Table 1 above. For Prairie Island alone, Xcel requested recovery of costs for capital expenditures of $340.73 more than in the CNs. In the Multi-Year Rate Case rate proceeding, the Department recommended disallowance of the revenue requirements associated with these capital costs since the Company had not justified charging more to ratepayers than the amounts in the 2008 CN, escalated to current dollars.[14] The Settlement was largely based on excluding these cost overruns.

The Commission's June 12, 2017 *Findings of Fact, Conclusions and Order* stated: "The ALJ found the Settlement's overall revenue requirement just and reasonable, finding that it was consistent with the Department's recommended revenue adjustments, including its recommended ROE."[15] Further, as indicated in the Commission's June 12, 2017 *Findings of Fact, Conclusions, and Order* at page 12, at the hearing, "Xcel confirmed that the Settlement does not provide for deferral of Prairie Island costs that are not recovered through the rates set in this case." However, Xcel could request recovery in its next rate case, going forward, of revenue requirements associated with the then-current rate base amount, appropriately reflecting the passage of time. Nonetheless, the burden would continue to be on Xcel to demonstrate the

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years 2008 to 2016, and from Company witness Timothy J. O'Connor dated November 2, 2015 in Docket E002/GR-15-826.

[11] Mr. Weatherby's Schedule 6, testimony dated January 29, 2016 in Docket No. E002/GR-15-826.

[12] Mr. Weatherby's Schedule 7, testimony dated January 29, 2016 in Docket No. E002/GR-15-826.

[13] Mr. Weatherby's Schedule 8, testimony dated January 29, 2016 in Docket No. E002/GR-15-826.

[14] Direct Testimony of Mr. Dale Lusti, in DVL-9 (second errata).

[15] See page 33 of the Commission's June 12, 2017 Findings of Fact, Conclusions and Order.

reasonableness of charging its ratepayers for any costs beyond the levels approved by the Commission in Xcel's 2008 CNs.

Therefore, for all of the above reasons, the Department retained Global Energy & Water Consulting, LLC ("Consultant") to investigate the history and costs that the Company experienced during the decision making of the LCM, EPU, and mandated compliance costs. While this review was never intended to be a fully supportable prudence review it follows the prudence review process and provides a fundamental foundation for a prudence test, if one were to be so ordered. The specific tasks of the review are provided below as they were provided to the Consultant:

(1) Identification of the facilities and corresponding costs for the plant that pertain:
   a. solely to Xcel's Extended Power Uprate for the Prairie Island plant,
   b. solely to Xcel's concurrent Life Cycle Management for the Prairie Island plant, and
   c. to both efforts.

(2) Examination of whether Xcel accurately identified the drivers and magnitudes of the drivers for the increases in costs for the Prairie Island plant from the levels Xcel initially proposed to the Commission in the 2008 certificates of need for:
   a. an extended power uprate (Docket No. E002/CN-08-509, abandoned in 2012), and
   b. the addition of storage casks that allowed the lives of the nuclear power facilities to be extended (Docket No. E002/CN-08-510).

(3) Examination of the reasonableness of decisions Xcel made or did not make, subsequent to the Commission's issuance of the two CNs in 2008, in incurring costs for the Prairie Island plant's nuclear generating units in response to changes in regulatory requirements of the NRC, and any other factors. Specifically, the examination should assess whether Xcel's decisions were necessary, reasonable and least-cost from an engineering perspective.

(4) Examination of whether Xcel's estimates of future costs for the Prairie Island plant for the license lives of 2033 and 2034 are reasonable. This investigation should include review of Xcel's projected O&M expenses for Prairie Island by FERC accounts for 2008 to the expected end of life (2033/2034). Review should consider but not be limited to the following

> areas of Prairie Island O&M expenses: Prairie Island Life Cycle Management, Prairie Island Extended Power Uprate, Spent Fuel, NRC Requirements, NRC requirements for Fukushima, NRC/State Fees, labor type costs, etc. Nuclear O&M expenses should be compared to Certificate of Need Docket Nos. E002/CN-08-509 (EPU) and 510 (Dry Cask Storage needed for LCM) and to amounts included in MNDOC's IRP model.

During the review and analysis of the capital and O&M spending at Prairie Island it has become increasingly clear that Xcel has had a history of difficulty with forecasting costs for major projects. It is also clear that Xcel has not, in the prior estimates of costs of proposed projects, taken advantage of the concept of using appropriate contingencies when the cost and budgeting knowledge base lacks sufficient engineering and planning activities at the time budgets are prepared for filings. This inadequate scoping or disclosure of potential costs is presented in the following discussions of the budgeting process for the CNs, Xcel's March 30, 2012 *Notice of Changed Circumstances and Petition* filing ("Changed Circumstances Petition") in Docket No. E002/CN-08-509 and the 2015/2016 budgeting.

In addition, there is a much larger budgeting issue to consider in Xcel's next IRP. The expiration of the current operating license for Prairie Island units 1 & 2 is now set at 2033 and 2034, respectively. Given Xcel's disclosure of significant cost increases expected for Prairie Island and the Commission's request for examination of the cost-effectiveness of continuing to operate the facilities to these dates, the record in the 2015 IRP included a high-level "bookend" analysis as to whether or not Prairie Island should be shut down earlier, such as in 2025.[16] While that preliminary analysis did not reach any conclusions about an early shut down, it noted that there were several scenarios where shutting the plant down early could actually reduce carbon dioxide emissions. Nonetheless, that analysis concluded that further information would be required to determine whether or not an early shutdown of Prairie Island would be reasonable.[17]

[16] The Department's 7/8/2016 Comments in Xcel's 2015 IRP, Docket No. E002/RP-15-21, see pages 26-38.

[17] The Commission's January 11, 2017 Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings required Xcel (among other things) to "describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island."

On the other hand, if Xcel intends to seek any extension of the lives of the Prairie Island units, it is important to know about any such plans as soon as possible. It is not too early to be seriously studying the consequences and options available to Xcel for the fleet additions necessary to meet the 2034 demands and beyond. In fact, these questions are expected to be developed in Xcel's next IRP, which is due July 1, 2019 and will include, for the first time, consideration of years beyond 2030.

To the extent possible, this report will follow the path provided in the tasks laid out in the above discussion.

SECTION 3.0 FACILITIES AND CORRESPONDING COSTS FOR PRAIRIE ISLAND AS TO:

SECTION 3.1 - SOLELY THE EXTENDED POWER UPRATE

Xcel first mentioned a potential upgrade to its nuclear plants in its 2004 IRP cycle (Docket No. E002/RP-04-1752). In the 2007 IRP (Docket No. E002/RP-07-1572), Xcel proposed to increase capacity at both the Monticello and Prairie Island nuclear plants. Specifically, in its December 14, 2007 IRP, Xcel stated that the upgrade to Prairie Island would add 171 MW and cost $291 million.[18] Xcel later filed its CN for both the capacity upgrade and the addition of storage casks with the Commission on May 16, 2008 (Docket No. E002/CN-08-509 and E002/CN-08-510, respectively). Xcel's EPU petition, dated May 16, 2008, revised the added capacity downward to 164 MW (82 MW for each unit) and increased the capital costs of the uprate to $322 million ($2008).[19] Xcel proposed to make the necessary modifications to install the EPU in its 2012 and 2015 refueling outages.[20]

Xcel's petition also identified that, whether or not the EPU was undertaken, Xcel expected to spend an estimated capital investment of $600 million for large capital investments including "the Unit 2 steam generators, additional spent fuel storage costs, and relicensing costs." [21] Xcel also expected to spend $20 million (2008 dollars) annually for life-cycle management, to keep Prairie Island "systems operating well."[22] (Xcel's most recent rate-case testimony included the $20 million annual costs for "routine capital").[23]

The application for the CN provided very high-level information about the projects necessary to add 164 MW of capacity to Prairie Island. The CN also provided very high-level cost estimates and corresponding financial analysis of proposed costs for the EPU rather than another option to add capacity to Xcel's system at that time. The initial CN identified that the

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[18] Xcel's initial filing, Docket No. E002/RP-07-1572, page 4-9.
[19] CN Application at page 6-11, Docket Nos. E002/CN-08-509/510.
[20] *Id*. at 2-3.
[21] *Id*. at 4-7.
[22] *Id*. at 4-6.
[23] Scott Weatherby's Supplemental Direct Testimony, Docket No. E002/GR-15-826, SLW-1, Schedule 2, page 1.

uprate would be achieved by "increasing the amount of heat produced in the reactor, which will result in more steam being produced by the steam generators."[24] Xcel did not expect "significant modifications to the Reactor, Nuclear Steam Supply System, or Emergency Core Cooling Systems."[25] In fact, Xcel stated that "very few modifications are required to the reactor and its support systems that produce steam."[26] However, Xcel did expect that the EPU would require that "the balance-of-plant systems that convert the steam produced in the steam generators to make electricity will need significant modifications."[27] Xcel stated that the "estimated installed cost of the 164 MW of additional capacity at Prairie Island achieved by power uprate is $2,011/kW [2008$]."[28]

Specifically, to increase the steam volume and to address the balance-of-plant ("BOP") work, Xcel identified the following in its CN Application as "[t]he major modifications"[29] needed to "the systems that convert the steam produced in the steam generators to electricity"[30] to increase the available fuel in the core as the primary work in the reactor:[31]

1. High pressure turbines would need to be replaced in both units, including the modification/replacement of exhaust piping and the turbine governor valves would need to be reworked.

2. Both generator rewinds and retrofits were under consideration, but Xcel had not decided at the time of the CN whether or not to do this work.

3. The generator step-up transformers ("GSU") were reaching the ends of their useful lives at the time of the CN; therefore, GSU replacement was inevitable. In addition, the GSUs were underrated for the power uprate conditions. While GSU replacement

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[24] CN Application Page 3B-29.
[25] *Id*.
[26] *Id*. at 3B-30.
[27] *Id*. at 3B-29.
[28] *Id*.
[29] *Id*. at 3B-30.
[30] *Id*.
[31] *Id*. at 3B-30 and 31.

was characterized as EPU, they could have just as well been characterized as LCM. In either case, this was a capital addition.

4. The moisture separator reheaters ("MSRs") at Prairie Island function to improve the steam quality of the high pressure turbine exhaust and superheat the steam before it enters the low-pressure turbines. Therefore, the existing MSRs needed to be replaced in order to meet the additional steam flow and reduce the pressure drop thereby increasing the pressure to the low pressure turbines.

5. The isophase bus (large cables carrying the electricity from the generator to the GSU's) conducts the electrical output of the main generator to the main transformer. Heat loads in the isophase bus duct increase with the higher power levels that result from the power uprate, resulting in a need to increase the cooling capability of the isophase bus ducts.

Xcel indicated that these five (5) main activities were the major modifications necessary to provide for the safe and reliable operation of Prairie Island with the originally proposed addition of 164 MW of the EPU. While these were the five major activities there were smaller areas of improvements to the plant that were necessary to operate with the increased capacity. These smaller projects would consist of the addition of new instruments and controls for the new equipment additions and other ancillary work to facilitate the EPU.

Global offers two observations about Xcel's list of five major EPU projects. First, the five major EPU projects did not include a significant component that later became the sixth (6^{th}) major item. After the first site visit with Xcel, Xcel's response to Department Information Request (IR) No. 730 in this proceeding indicated that the Company confirmed that it was not until their IRP filing on December 1, 2011 in Docket No. E002/RP-10-825 that they included any narrative regarding the sixth major item: addition of new low-pressure turbines. Specifically, Xcel stated in its December 1, 2011 *Resource Plan Update* in that proceeding (p. 33-34) that the addition of low-pressure turbines was "not justifiable":

> *Low Pressure Turbines*. Our estimate of the potential capacity increase has been scaled back by approximately 29 MW. To achieve that last 29 MW increment, it now appears we would have to add improvements to the plant's low pressure turbine stages and make significant changes to condensers to reduce turbine backpressure which affects performance. Currently, our estimate of the cost of these additions could approach as much as $200 million, making the last 29 MW increment not justifiable.
>
> After these two adjustments, we estimate 117 MW of capacity increases can be captured with the remaining EPU program.

Xcel's response to IR No. 726(c) in this proceeding stated that Xcel's "Strategist modeling for the 2008 CON included $100 million in unescalated costs for the low pressure turbine installation." This identified amount ($100 million) is approximately 31 percent of the total estimated costs of $322 million. However, there was no formal identification of the need or schedule for low-pressure turbine work in the EPU filing, even though Xcel discussed the other five items listed above.

Global notes that it is unclear why such a large cost individual item was not included in the original EPU narrative in the 2008 CN application, since the low-pressure turbine project was listed as one of the "six hardware related items on the plant modification list that had the potential for long lead times"[32] in the April 30, 2008 "White Paper" prepared for the *Initial Funding Report* by Westinghouse for Prairie Island.[33] While Westinghouse identified this project to Xcel, the Westinghouse report indicates that "no initial funding project study (was) performed."[34]

While this information at least indicates that there was identification of the possible need for the low-pressure turbine work, this response actually creates more questions than it answers; i.e., if the project was identified to Xcel why did Xcel not pursue a funding study prior to submitting its application for a CN? Specifically, why did Xcel not request that Westinghouse (or another entity) further investigate the low pressure turbine project and provide some form

[32] IR – 720 Attachment A at 13.
[33] *Id*. entire report.
[34] *Id*. at 10.

of a recommendation to be considered in the CN proceeding? Leaving this action item in an "open" or unresolved condition does not explain the overall necessity of addressing low-pressure turbines for the project and the consequences of failure to address this aspect of the EPU project prior to filing the 2008 CN for the EPU.

Four months after Xcel filed its December 1, 2011 "Resource Plan Update" in Docket No. E002/RP-10-825 to remove the LP turbines but retain all other aspects of the EPU, the Company filed its April 2, 2012 Notice of Changed Circumstances in the CN Docket No. E002/CN-08-509 to cease the EPU entirely. Since the 2010 IRP analysis overlapped the Notice of Changed Circumstances, the Department's analysis filed in the 08-509 CN docket examined the effects of no EPU at Prairie Island, rather than the effects of removing the low pressure turbines but retaining the rest of the EPU. This analysis is discussed below.

Xcel provided more specific information in the Company's 2013 rate case (Docket No. E002/GR-13-868) about why the Company decided not to upgrade the high-pressure turbines, low-pressure turbines or modify the governor valve. Specifically, Mr. Scott McCall, who was the Manager of Site Projects at Prairie Island and was responsible for leading capital projects at Prairie Island, stated the following in his November 4, 2013 Direct Testimony in the 2013 case regarding the EPU at Prairie Island:

> Q. WHAT CHANGES IN THE SCOPE OF WORK DID THE COMPANY IDENTIFY?
>
> A. The Company changed the scope of work by deciding not to upgrade the HP Turbine per the original scope, removing the governor valve modification, and eliminating the LP Turbine upgrade.
>
> Q. WHY DID THE COMPANY DECIDE NOT TO UPGRADE THE HP TURBINE?
>
> A. We determined that upgrading the HP turbine to a single-flow design would not be cost-effective because we would need to change the whole turbine pedestal foundation. We therefore selected enhanced double-flow design as a more cost-effective alternative. This reduced the power increase by approximately 3.5 MWe / unit.

Q. WHY DID THE COMPANY DECIDE NOT TO MODIFY THE GOVERNOR VALVE?

A. To determine the approximate cost of a governor valve modification, we consulted with an industry vendor and determined that the modification did not make economic sense for the potentially small MW gain. This reduced the power increase by approximately 2 MWe/unit.

Q. WHY DID THE COMPANY DECIDE NOT TO UPGRADE THE LP TURBINE?

A. We determined that upgrading the LP turbine could create system backpressure during summer operating conditions, which would result in losses that effectively canceled out winter power gains. Any net gains in power output would be negligible to minor under this scenario and would result in an unfavorable cost-benefit ratio for this modification. Removing the LP turbine upgrade from the scope of modifications potentially reduced the projected power increase by another 10.5 MWe/unit.[35]

The second observation Global offers about Xcel's list of EPU units is that, as noted above, even if Xcel had not pursued an EPU, it still would have been necessary for the Company to undertake some of the capital projects identified for the EPU, to replace (but not upgrade) aging equipment as part of its LCM responsibilities. While Xcel mentioned a few LCM upgrades (Unit 2 steam generators, additional spent fuel storage costs, and relicensing costs, as noted above), the Company did not distinguish such costs between the LCM and EPU. Further, Xcel acknowledged that the Company did not provide a complete list of items that would need to be replaced even if the EPU did not proceed.[36]

Given that the EPU and LCM were two different regulatory proceedings, and clearly are severable projects, to be accurate, Xcel should have identified in the filing to extend the lives of the Prairie Island plants the costs of replacing worn-out equipment, and then identified

[35] Scott McCall's Direct Testimony, Docket No. E002/GR-13-868, page 24.

[36] CN Application Page 4-7, acknowledging that Unit 2 steam generators, additional spent fuel storage costs, and relicensing costs was "not a definitive list" and instead was "representative of the order of magnitude" of investments due to the LCM.

incremental costs of upgrading the size of equipment or timing for the installation for the EPU. Such an approach would have given a more accurate picture of the costs of extending the lives of the Prairie Island units as opposed to upgrading the facilities. Under such an approach, would have been simple to identify capital costs that were abandoned once the Company decided not to pursue the EPU. Even though there is not sufficient information available to identify which capital costs are due to the LCM as opposed to the EPU, it is likely that the majority of the capital costs would have been assigned to the LCM. This issue is discussed further below.

Xcel provided in its 2013 rate case a list of the abandoned costs of the EPU by year,[37] in which Xcel identified that the only abandoned costs assigned to the EPU at that time were for the costs of pursuing an EPU License with the NRC ($65,843,801)[38] and a minor capital cost of installing a Zinc Injection System ($242,592), for a total of $66,086,393 (99.6 percent of the costs Xcel identified were for the EPU license). The majority of the total costs ($56,364,523,[39] or 85 percent) were for contractor services for the EPU License with the NRC.

[37] Scott Weatherby's Direct Testimony, Docket No. E002/GR-13-868, page 11.
[38] Scott Weatherby's Direct Testimony, Docket No. E002/GR-13-868, SLW-1, Schedule 5E.
[39] *Id*. at Schedule 5D.

Table 2: EPU Costs for EPU License and Zinc Injection System (Total Company $)

		Split of Column A			*Final EPU Only*
	Column A	Column B	Column C	Column D	Total C + D
Costs through:	Total EPU/LCM Costs in Work orders 10532527 and 10562058 (without AFUDC)	LCM/Other Costs Charged to EPU Work order for Year	EPU Costs Charged to EPU Work order for Year	AFUDC recorded by Year	Costs in EPU Work orders 10532527 and 10562058 (with AFUDC)
12/31/2006	$854,392	$ 0	$ 854,392	$32,491	$886,883
12/31/2007	$1,065,379	$ 0	$ 1,065,379	$110,323	$1,175,702
12/31/2008	$2,143,914	$ 146,911	$ 1,997,003	$256,665	$2,253,668
12/31/2009	$15,004,650	$ 1,867,569	$13,137,081	$688,075	$13,825,156
12/31/2010	$28,984,960	$ 1,578,912	$27,406,048	$2,856,147	$30,262,195
12/31/2011	$17,114,563	$ 1,572,482	$15,542,081	$5,287,676	$20,829,757
12/31/2012	$6,785,963	$ 701,554	$ 6,084,409	$4,119,947	$10,204,356
12/31/2013				($552,802)	($552,802)
Total	**$71,953,821**	**$5,867,428**	**$66,086,393**	**$12,798,523**	**$78,884,916**
		Transferred to various LCM Work orders			Transferred to Regulatory Asset

In that 2013 rate case, the Commission provided the following helpful background information on pages 29-30 of the May 8, 2015 Findings of Fact, Conclusions and Order:

> The Company seeks rate recovery of $78.9 million in costs incurred for a cancelled project to increase the generating capacity of its Prairie Island nuclear plant. The $78.9 million figure includes $66.1 million in total expenditures and $12.8 million in accrued AFUDC (Allowance for Funds Used During Construction), the net cost of money used for construction.
>
> On December 18, 2009, the Commission issued a certificate of need for the project, called an "extended power uprate." The Commission found that there was a need for the additional 164 MW of electricity the project would generate and that the extended power uprate the Company proposed was the most

reasonable means developed in the record for meeting that need.[26] The project was one of more than 100 similar projects proposed throughout the country at that time; the order stated that as of the date of issue the federal Nuclear Regulatory Commission (NRC) had completed its review of some 118 power-uprate projects.[27]

As the project progressed, problems developed. In January 2011, the Company determined, in conjunction with Westinghouse, the manufacturer of the Prairie Island nuclear reactors and the firm conducting the engineering analyses for the project, that an uprate of 164 MW could not be achieved cost-effectively; the Company lowered its uprate goal to 132 MW.[28]

In March 2011, there was a disaster at the Fukushima Daiichi nuclear power plant in Japan. This disaster prompted changes to the NRC review process, which became lengthier, more detailed, increasingly backlogged, and more expensive. In August 2011, the Company had a meeting with NRC staff that led it to conclude that heightened review requirements would substantially increase the cost of preparing its application for an NRC license and would delay project implementation by about two years.

At about the same time, a nationwide pattern of significant cost overruns for uprate projects similar to the one planned for Prairie Island emerged. Meanwhile, Company sales forecasts indicated a persistent softening of demand for electricity within its service area. And the price of natural-gas generation, a potential competitor of increased Prairie Island generation, continued to decline, due to structural changes in the natural-gas sector.

On October 7, 2011, the Company filed a letter in its pending resource-plan case apprising the Commission that it saw a need for a comprehensive update of its 2011–2025 resource plan in light of obstacles to completing the Prairie Island extended power uprate on schedule. On December 1, 2011, it filed the update, stating, among other things, that the extended power uprate might no longer be in the public interest and that it planned to file a Notice of Changed Circumstances in the certificate-of-need docket requesting Commission review of that issue.

Meanwhile, the Company reduced spending on the uprate in the third quarter of 2011 and ended all spending by the end of that year, with the exception of the Westinghouse contract, whose early-termination penalty provisions would have been nearly equal to the cost of performance.

On April 2, 2012, the Company filed the Notice of Changed Circumstances in the certificate-of-need docket. The Commission initiated an all-stakeholder comment-and-review process. On February 27, 2013, the Commission issued an order terminating the certificate of need prospectively, explicitly deferring the issue of cost recovery for later treatment. Cost recovery issues will be addressed below.

26 *In the Matter of the Application of Northern States Power Company for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, Docket No. E-002/CN-08-509, Order Accepting Environmental Impact Statement and Granting Certificates of Need and Site Permit with Conditions (December 18, 2009).
27 *Id*. at 8.
28 ALJ's Report ¶ 438.

Based on all of the information above, along with recommendations of the Department, the Minnesota Chamber of Commerce, Xcel and the Administrative Law Judge in the 2013 rate case, the Commission permitted Xcel to recover the identified cancelled project costs (EPU licensing plus AFUDC and Zinc Injection System) totaling $78.9 million total Company over 20.3 years, with a return on the unamortized balances at Xcel's 2.24 percent cost of debt.

What remains unclear is what other costs the Company would have incurred if Xcel had continued to pursue the EPU. Xcel's response to IR No. 731 in this investigation indicates that Xcel estimates it avoided $187 million in costs due to not proceeding with the EPU. The difference between the $66,086,393 total test-year costs that Xcel assigned to the EPU in its 2013 rate case and the $187 million that Xcel estimated in total avoided costs due to not proceeding with the EPU is approximately $121 million. It would be helpful for Xcel to identify the remaining costs that were avoided due to not proceeding with the EPU, to have a better understanding of the costs of Prairie Island for its remaining life.

As discussed above, even if Xcel had not pursued an EPU, aging equipment would have required replacement as part of the LCM responsibilities. Thus, for clarity, Xcel should identify the status (whether installed or not and, if not, whether Xcel has any plans to install in the future) of each of the individual components Xcel identified in its original EPU CN petition in E002/CN-08-509 and corresponding costs making up the $121 million total that the Company expected to incur for the EPU but will now avoid.

The next section discusses Xcel's LCM.

Section 3.2 - Solely the Concurrent Life Cycle Management

While the project characterized as LCM did not, in itself, require the filing of an application for a CN according to Commission rules, adding more storage casks at Prairie Island did require a CN. The LCM was only briefly mentioned in the CN application for the extension of the life of Prairie Island, where Xcel simply identified the LCM as an alternative that was used in the Strategist© capacity expansion model.

Xcel presented the LCM alternative as one that would provide for the continued operation of Prairie Island through its then-current license period of 2013 & 2014 for Units 1 & 2, respectively, compared to operating at its capacity of 1,095 MW for the extended life, if granted by the NRC (2033 & 2034, respectively). The additional capital investment estimated by Xcel for continued operation through the extended license was $1.2 billion ($2008).[40] The cost of the LCM was part of the $1.2 billion cost that Xcel represented to the Commission as justifying additional storage casks at Prairie Island. Xcel stated that the Company "routinely invest[s] and upgrade[s] systems to that the plant maintains safe and highly reliable operations. We invest an average of about $20 million dollars annually ($10 million per unit) in the Prairie Island plant to keep systems operating well."[41] However, the CN did not provide any further explanation of the LCM or the increase in capital necessary to maintain safe and reliable operations.

Company witness Dennis Koehl's November 3, 2010 Direct Testimony in Docket No. E002/GR-10-971 provided somewhat more description of the LCM projects. That testimony presented only a brief discussion of the LCM projects by explaining that the LCM projects

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[40] 08-509 CN at 4-12.
[41] *Id*. at 4-6.

"include cable replacements, breaker replacement, upgrades of the main control room, replacement of feed-water heaters, and replacement of the Unit 2 steam generator at Prairie Island."[42] Mr. Koehl did not present a more detailed list of LCM type projects nor the associated costs in the text of his testimony in 2010. His schedule listed the following Major Projects in Support of Capital Additions for Prairie Island in 2010 and 2011:[43]

- *10PRI2000 - Nuclear-Prairie Island*
  - Major Projects within Grandparent:
    - 11230292 - Prairie Island 10CFR73 Continuous Detection
    - 11230304 - Prairie Island 10CFR73 No Single Act
    - 10956900 - Prairie Island Cyber Security
    - 11230311 - Prairie Island 10CFR73 Pathways
    - 11368101 - Prairie Island Force on Force
    - 11044898 - Prairie Island NFPA805 Fire Model
    - 11230606 - Prairie Island Security Enhancements
- *10PRI2002 - Nuclear-Prairie Island-Life Extension* 10386846 - PI-LICENSE RENEWAL PROJECT

Mr. Koehl identified the total costs for these projects in the 2010 and 2011 test years as $115.8 million for the "Major Projects within Grandparent" and $48 million in 2011 for NRC license renewal. Mr. Koehl defined LCM projects as" those ongoing capital projects necessary to keep the plant operating safely and reliably."[44]

As a more clearly articulated definition of LCM, life cycle management of a nuclear power plant includes typical and sometimes atypical capital and O&M projects warranted to maintain the safe, reliable and efficient operation of the Prairie Island units. While LCM projects are not necessarily routine, they are confined to projects that are required to continue the operations of Prairie Island without changing the current design basis or electric output, materially.

[42] Mr. Koehl's Direct Testimony at 28-29, Docket No. E002/GR-10-825.
[43] *Id*. at DLK-1, Schedule 6.
[44] *Id*. at 29.

As noted above, in Xcel's 2013 rate case, the Company categorized costs between the EPU and LCM. As to the $5,867,428 in costs identified for the LCM in Table 2 above, Xcel listed the cost categories shown in Table 3 below:

Table 3: LCM and Other Costs Xcel Identified in Its 2013 Rate Case[45]

LCM or Other Description	**2008**	**2009**	**2010**	**2011**	**2012**	**Grand Total**
LCM Projects						
Beacon TSM	$2,285	$32,890	$62,972	$153,342	$252,003	$503,492
Alternate Source Term	7,021	783,435	387,107	421,668	25,088	1,624,320
Leak Before Break	762	401,863	414,046	168,683	155,047	1,140,401
Spent Fuel Pool Criticality Analysis	762	10,963	125,825	217,418	25,742	380,710
Unit 1 LCM - Generator Replacement	33,259	116,624	79,688	59,177	21,832	310,579
Unit 2 LCM - Generator Replacement	33,259	116,624	79,688	59,177	21,832	310,579
Unit 1 LCM - GSU Transformer Replacement	33,259	116,624	79,688	59,177	21,832	310,579
Unit 2 LCM - GSU Transformer Replacement	33,259	116,624	79,688	59,177	21,832	310,579
Sub Total	$143,866	$1,695,647	$1,308,702	$1,197,819	$545,208	$4,891,239
Other Non-EPU Projects						
TN-40H Design & Licensing (new cask design)	$0	$0	$5,691	$2,829	$0	$8,520
Relicense Independent Spent Fuel Storage Installation	$0	$0	$0	$0	$6,700	$6,700
Unit 2 Steam Generator Replacement Transfer Out (Preliminary)	$0	$0	$1,000,000	$3,345	$234,168	$1,237,513
Unit 2 Steam Generator Replacement Transfer Returned	$0	$0	($1,000,000)	($3,345)	($219,580)	($1,222,925)
License Renewal Phase II - Component Design Basis Review	$3,046	$171,921	$264,517	$371,836	$135,059	$946,379
Sub Total	$3,046	$171,921	$270,208	$374,665	$156,347	$976,187
Total - LCM & non-EPU costs	$146,912	$1,867,568	$1,578,910	$1,572,484	$701,555	**$5,867,426**

[45] *Id*. at Schedule 5F.

As with any list of project components, regardless of accounting, capital or O&M, there are any number of important small projects that are simply too numerous to identify due to their relatively small cost when compared to the more major cost items; Prairie Island's LCM list is no different. However, there are also significant LCM project components demanding separate identification and accounting, such as the Unit 2 Steam Generator Replacement, with a final cost of $270 Million.

Critical to Global's analysis was a discussion of how the Company accounted for transfers of costs from the EPU costs, particularly arbitrary "splits" of costs invoiced in a "total invoice." Company witness Mr. Weatherby attempted to explain the division or transfers of these EPU splits over to LCM or other accounts as follows:[46]

> **WEC 1% LCM** – Transactions with this "split" designation were Westinghouse invoices that were assumed to be 1% LCM. Of this 1% of the invoice line item, the dollars were split as follows per project team's judgment: 10% Measurement Uncertainty Recapture (MUR), 30% Beacon (TSM) [Technical Specifications Monitor], 10% SFPCA [Spent Fuel Criticality Analysis], 10% LBB [Leak Before Break], and 40% LR II-CDBR [Component Design Review].
>
> **HELB 10% LCM** – Transactions with this "split" designation were Automated Engineering Services invoices where project team assumed 10% was assumed [sic] to be related to the LCM work order LR II-CDBR for High Energy Line Break (HELB) calculations.
>
> **GEN 15% GSU 15%** - Transactions with this "split" designation were Preferred Licensing Services invoices where project team assumed 15% was related to the Unit 1 and Unit 2 electric generator work orders and 15% was related to the Unit 1 and Unit 2 GSU transformer work orders.
>
> **GEN 25% GSU 25%** - Transactions with this "split" designation were three vendor's invoices where project team assumed 25% was related to the Unit 1 and Unit 2 electric generator work orders and 25% was related to the Unit 1 and Unit 2 GSU transformer work orders. The invoices with this split were billed by Amalgamated Results Group, Professional Project Partners, and Sun Technical Services.

[46] Mr. Weatherby's November 4, 2013 Direct Testimony at SLW-1, Schedule 7, Docket No. E002/GR-13-868.

> **GEN 50% GSU 50%** - Transactions with this "split" designation were five vendors' invoices where project team assumed 50% was related to the Unit 1 and Unit 2 electric generator work orders and 50% was related to the Unit 1 and Unit 2 GSU transformer work orders. The invoices with this split were billed by Delta Energy Services, Engineering & Management Specialists, NPTS, Inc., N-Star Project Services, and Seek Careers/Staffing.

The handling of these "splits" points out two concerns with the accounting for EPU and LCM projects in the methods originally selected by the Company.

1) Handling the splits by assumptions made by project team members does not provide a reasonably auditable trail of these costs that meet expectations under generally accepted accounting principles. It also relies almost exclusively on the project management team's understanding and decisions at the time they were made. Understanding and accounting for such treatment is lost over time. Clearly, this approach is not the best way to handle such splits.
2) Global noted above the difficulty of tracking both costs and technical objects of the EPU and LCM projects. Based on the methodology Xcel used for reassigning costs away from EPU to LCM and the commingling of LCM projects with EPU projects, the lack of adequate transparency hampers the ability of a third party review to track the history and decision-making of the Company from a regulatory point of view.

Xcel provided additional information about LCM work in Xcel's most recent (2015) rate case. Subsequent to Xcel's October 2, 2015 filing in Docket No. E002/RP-15-21 noted above, the Commission required Xcel to file more information in both the 2015 IRP and the 2015 Rate Case:

> To expedite record development on the prudence of Company expenditures on the Life Cycle Management program at its Prairie Island nuclear plant, the Company will be required to file, no later than January 29, 2016, supplemental schedules and testimony that:
>
> 1) Describe and compare projected and actual Life Cycle Management costs (and, to the extent relevant, Extended Power Uprate costs)

from 2008 through 2020 by generating unit and year, including the proposed 2016 test year in this rate case, and the 2017 and 2018 plan years. The descriptions and comparisons should include all changes and updates to projected costs from 2008 on and should include all cites to relevant certificate of need, resource plan, and general rate case dockets.

2) Compare the relevant parts of the proposed 2016 test year, the 2017 plan year, and the 2018 plan year to the proposed five-year capital budget in the Company's pending resource plan, docket E-002/RP-15-21.[47]

In his testimony filed in compliance with this requirement, Company witness Mr. Weatherby captured an appropriate definition: "Generally, speaking, [sic] however, LCM work is completed through hundreds of small, medium and large capital projects performed to maintain the material condition of a nuclear generating unit."[48]

Mr. Weatherby's Supplemental Testimony identified the project components listed in Table 4 below as attributable exclusively to the LCM:[49]

[47] Commission's December 22, 2015 Notice of and Order for Hearing at 4.
[48] Cite: Mr. Weatherby's January 29, 2016 Supplemental Direct Testimony in Docket No. E002/GR-15-826, Page 11.
[49] *Id*. at SLW-1, schedule 5.

Table 4: Xcel's Identification of LCM Components:

Reactor Coolant Pumps (RCP) rebuilds	Heater Drain Tank Speed Controls upgrade
Motor Rewinds & Replacements	Cooling Tower/Water system replacements
Electric Generator Replacement	Transformer replacements
Foxboro Control Module replacement	Battery Room & Feedwater Pump Room Cooling
Plant Process Computer System upgrade	Screenhouse header pipe replacement
Fan Coil Unit replacement	Radiation Monitor upgrade
Safeguard pump redesign	Voltage Regulator replacement – Diesels
Voltage Regulator replacement – Generator	Various Cooling System upgrades & replacements
Various Control System replacements[50]	Information Technology capital improvements
Vibration Monitoring Upgrades - Turbine/generator	

It is likely that the majority of the costs of the components identified above are reasonably classified as LCM related. However, as noted above, it is possible that a portion of some of the replacement equipment should have been categorized as EPU related, if Xcel installed equipment sooner than would otherwise have been the case due to the EPU or if Xcel installed larger equipment for the EPU.

Section 3.3 – Attributable to Both the EPU and LCM

Projects that are identified as LCM should not ever be characterized as "attributable to both." LCM has very specific attributes in that they are necessary to maintain current operational safety, reliability and efficiency without materially changing the design basis or electrical output of the plant. Even if an LCM project is to be installed, constructed or initiated within the same outage as an EPU project, the LCM work, costs and other information should

[50] Mr. Weatherby's schedule 5 listed "Various Cooling System upgrades and replacements" as a separate line item from "Various Cooling System replacements" so both items are listed above.

be separately identifiable from the EPU work, costs, and so forth. That principle does not preclude the LCM project from providing benefits to an EPU, but such LCM projects are required regardless of whether an EPU is undertaken or not. If a particular project is identifiable as necessary for the EPU then it should be included within the scope of EPU. If the EPU is canceled, as in the Prairie Island case, then the particular project should also be canceled. This principle and approach should establish the basis for what are LCM costs versus EPU costs.

This principle should not be confused with the accounting methodology used to capture either EPU or LCM costs. The accounting for and the characterization of EPU and LCM costs are two wholly separate activities. In both cases, the accounting is of a capital budget basis but it is important for utilities such as Xcel to track such significant and separable capital projects carefully, regardless of whether any two projects are included within the same work-order or the same bill from a vendor to allow the Commission to reach determinations based on an adequate record.

Global's recommendation is that whenever Xcel obtains approval from the Commission to undertake a project, such as Xcel obtained for the EPU (and the additional storage and life of Prairie Island), since such projects are one-time projects of definable scope as identified in the utility's petition, costs for such projects must be accounted for under their own specific work-orders. The EPU must be accounted for separately, regardless of whether it takes one, two, or three outages to accomplish all of the work. The LCM projects should likewise be accounted for separately under the current process the Company employs in its filings with the Commission, "routine capital, reliability, large capital," etc.

Never should a project that is defined as EPU or LCM later have projects within those characterizations shifted from one characterization to another. As clearly articulated by Company witness Mr. Weatherby, "LCM work is completed through hundreds of small, medium and large capital projects *performed to maintain the material condition of a nuclear generating unit*."[51] (Emphasis Added). All of those such projects should be readily identified and tracked over the life of a plant.

[51] Cite: Mr. Weatherby's January 29, 2016 Supplemental Direct Testimony in Docket No. E002/GR-15-826, page 11.

SECTION 4.0 XCEL'S IDENTIFICATION OF CAUSES AND SIZES OF COST INCREASES

Section 4.1 - EXTENDED POWER UPRATE (DOCKET NO. E002/CN-08-509, ABANDONED IN 2012)

The purpose of this report is not to recommend any cost disallowance, nor is this specific discussion intended to suggest any cost disallowance. However, this report notes that it would have been better if Xcel had been more transparent about the work at the Prairie Island facilities throughout the process of seeking CNs and deciding not to pursue the EPU. The report offers recommendations on a going-forward basis with the intent to address these issues.

The question of whether Xcel accurately identified the drivers and magnitude of the drivers for the increases in costs for the Prairie Island plant from the levels Xcel initially proposed to the Commission in the 2008 CN focuses on a significant problem with Xcel's internal project development activities, responsibilities to inform the Commission about cost deviations, and the overall accuracy of Xcel's budgeting process. Xcel lacked an adequate process structure to identify reasonable estimates of costs for these significant capital projects during the development of the 2008 CN, which continued with each cycle of review of budgets and when Xcel filed its Changed Circumstances Petition with the Commission.

During the preparation of the budget documentation to support the original CN for the EPU and the Dry Cask Storage additions, Xcel used high level cost estimates that Global considers not to be of a level of accuracy necessary to use for Strategist alternative planning purposes or for the Application itself, without use of appropriate contingencies, as discussed below.[52] Evidence to support this conclusion comes directly from Xcel, which made the following statement in their Changed Circumstances Petition:[53]

> We [Xcel] filed our Application for a Certificate of Need for an Extended Power Uprate ("EPU") at Prairie Island in May 2008, proposing a 164 MW project costing approximately $322 million to be implemented during 2014 and 2015 refueling outages. The Commission granted the Certificate of Need on December 18,

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[52] Global found during the Monticello Cost overrun analysis in Docket No. E002/CI-13-754 that Xcel consistently provided much lower estimates of Contingencies in their budget estimates. By doing so Xcel, was consistently having to revise its budgets upward beyond the bounds of previously stated budgets.

[53] Xcel's March 30, 2012 Changed Circumstances Petition, Docket No. E002/CN-08-509, page 4.

> 2009, finding the uprate program provided value to our customers, satisfied the Commission's rules, and was the best alternative on the record. Since that approval, we began the engineering, analysis, and design work necessary for the Nuclear Regulatory Commission's ("NRC") licensing process.

Troubling about Xcel's statement above are the following:

1) A material issue with Xcel's budgeting for such capital projects is the Company's difficulty in accurately planning for the timing of the EPU projects. For example, the reference in the above statement to the 2014 date differs from the date stated in the actual CN, which indicated that Unit 1 would be addressed during the 2012 refueling outage and Unit 2 during the 2015 refueling outage.[54]
2) Following the above statement in the Changed Circumstance Petition, Xcel stated,

> The largest component of our work to date relates to preparation of our license amendment request ("LAR"), which must adhere to the NRC's Review Standard for Extended Power Uprates. The LAR package generally takes between 12-18 months to complete and includes extensive information regarding the impact of proposed changes to the plant, detailed design information, and complex engineering and operating analyses.[55]

Thus, according to Xcel's own statement, the Company did not include the engineering, analysis, and design work necessary for the NRC licensing process prior to submitting its CN application.

While it certainly would not have been necessary to have all of the analysis complete, Xcel should have undertaken sufficient engineering analysis to develop reasonable cost and timing analyses, or in the alternative should have estimated costs that included a significant contingency, according to industry standards. For example, the standards identified in a prior proceeding are shown in Table 5, below.

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[54] Cite: Application for CN, dated May 16, 2008 on page 3B-29, in Docket No. E002/CN-08-509.
[55] Xcel's March 30, 2012 Changed Circumstances Petition, Docket No. E002/CN-08-509, page 4.

Table 5: Cost Estimate Classification Matrix for the Process Industries[56]

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges (a)
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

3) Xcel commissioned Westinghouse, along with its subcontractors Sargent Lundy and the Shaw Group to perform an Extended Power Uprate Initial Funding Project, which was transmitted to Xcel on March 30, 2008. Since this study was performed by Westinghouse, a contractor with a respected reputation for this type of work, it is unclear why Xcel would claim that they did not initiate engineering until after the granting of the CN.

In Global's opinion, Xcel should have had a much more detailed understanding of the costs of the EPU prior to running Strategist options and certainly prior to the Application for the

[56] Surrebuttal testimony of Department Witness Mark W. Crisp, P.E., 9/19/2014, Docket No. E002/CI-13-754, Attachment 1, page 2 of 10.

CN, or should have included a significant cost contingency in the proposal to reflect the status of the cost scoping that had and had not been done. Such an approach would have allowed for a more reasonable comparison between Xcel's proposals and alternatives that were available at that time, with appropriate contingencies for all costs based on information that was known at that time. Instead, Xcel indicated in its response to IR No. 732 in this investigation that the Company included a contingency of only $34 million, which is a 10 percent contingency, falling into the Class 3 or Class 4 contingency above. Such an approach understates the cost of the EPU and gives an unfair advantage to the Company's proposal when compared to other resources, leaving ratepayers facing the risk of footing the bill when actual costs are higher than the contingencies. It appears that Xcel has recently been attempting to improve its procedures to preclude such future occurrences, but those processes were not in place in 2008.

Based on Global's analysis of the costs and the drivers for the increases in cost and schedule delays with the EPU, Global concludes that Xcel, at that time, did not identify the drivers and magnitude of the drivers impacting the EPU project in a reasonably accurate manner. Xcel struggled with the drivers and magnitudes even up to the actual filing of the Changed Circumstances Petition. An additional example of the difficulties Xcel had with the drivers includes their statement in the Change Circumstance Petition that:

> To analyze the new timing and reduction in size, we repeated the analysis of alternatives in our Certificate of Need proceeding assuming the EPU was implemented during the 2016 and 2017 refueling outages and at a size of 135 MW. This involved re-running the same Strategist modeling used in our Certificate of Need analysis *without any changes to other assumptions*.[57] (Emphasis Added).

When Xcel filed its Changed Circumstances Petition, the question before the Commission was whether the uprate of Prairie Island continued to be a cost-effective resource, going forward. Thus, while Xcel's analysis focused only on the facts that were known at the time of Xcel's CN, Xcel's focus should have also been on demonstrating whether the EPU was a cost-effective resource going forward.

[57] Xcel's March 30, 2012 Changed Circumstances Petition, Docket No. E002/CN-08-509, page 8.

The Department's June 12, 2012 analysis examined not only that backward-looking question but also whether or not the EPU continued to be cost-effective. Under all scenarios, even Xcel's zero externalities assumption, the EPU continued to demonstrate cost-effectiveness. Nonetheless, since Xcel continued to state that the EPU should be abandoned, after the Commission issued an Order to Show Cause on November 7, 2012, asking parties to submit filings to demonstrate why the Commission should not terminate Xcel's Prairie Island Uprate Certificate of Need prospectively, the Commission allowed Xcel to terminate its CN.

The Commission's February 27, 2013 Order Terminating Certificate of Need Prospectively provided on pages 3-4 the following helpful background and the basis for the Commission's Order Terminating Certificate of Need Prospectively, which approved Xcel's Changed Circumstances Petition:

> Xcel initially petitioned for relief under Minn. R. 7849.0400, subp. 2(H). When a project developer receives a Certificate of Need to build a large energy facility, this rule directs the developer to notify the Commission and other parties if a substantial change arises in the size, type, timing, or ownership of the proposed facility. The rule contemplates that the developer will seek to maintain its Certificate of Need and continue to build its proposed facility. But as of October 2012, Xcel no longer seeks that outcome.
>
> Instead, Xcel provides analysis supporting the conclusion that, due to various changing circumstances, it is now in the public interest to discontinue the uprate project. In response to this analysis, and consistent with Minn. R. 7849.0400, the Commission solicited comments from parties on the proposed termination of Xcel's Certificate of Need.
>
> Having reviewed the record, the Commission concludes that 1) Xcel has demonstrated that it is in the public interest to discontinue its uprate project, and 2) no party has shown cause for continuing the construction of that project. Consequently the Commission will terminate Xcel's Certificate of Need prospectively.
>
> … The Commission finds that the record does not demonstrate cause to reject Xcel's proposal on grounds of adequacy of finances for emergency services.
>
> Finally, the Commission clarifies that its decision to terminate Xcel's Certificate of Need does not address Xcel's resource needs; that topic is being addressed in the context of Xcel's resource

> planning docket. Nor does the decision address the prudence of Xcel's investments or the recovery of those costs; those judgments may be made in the context of Xcel's rate case. [Footnotes omitted]

While the above discusses concerns with Xcel's budgeting for proposed projects, Global is pleased to note that Xcel appears to have made substantial improvements in the Company's budgeting process and financial accountability over the last 3-4 years. During Global's face-to-face meeting with Xcel management personnel at Prairie Island, Global learned of Xcel's commitment to greatly improve their knowledge base through new hires, staffing reassignments and improved processes. Examples of changes that should result in better performance going forward are: establishing joint engineering teams utilizing Prairie Island and Monticello personnel to address problems or projects at each Plant, establishing closer working relationships between plant and general office engineering teams, and establishing Teams of engineering, plant personnel and contractor personnel to scope and budget projects.

Moreover, in response to an information request as to how Xcel will hold third-party contractors accountable for their work at the Prairie Island plants, Xcel stated that the Company implemented specific terms and conditions to hold third-party contractors accountable to timely and effective performance, including:

- Letters of credit,
- Liquidated damage provisions,
- Risk-sharing mechanisms (e.g. cost-sharing bands, putting some of the contractor's fee at risk if costs are higher and/or outages are longer than expected, regardless of fault for cost increase or delay), and
- Fixed-price terms.

All of these changes should help Xcel's Prairie Island facilities perform better in the future and provide benefits to budget preparation and to the accuracy level of data provided to the Commission regarding Prairie Island's operations.

Section 4.2 - ADDITION OF STORAGE CASKS TO EXTEND LIVES OF PRAIRIE ISLAND FACILITY (DOCKET NO. E002/CN-08-510).

The Dry Cask Fuel Storage capital addition to provide storage of spent fuel on-site at Prairie Island in the independent spent fuel storage installation ("ISFSI") are needed capital expenditures in order for the two units to continue operation through the 2033 & 2034 extended license period. However, once again the escalation of pricing between the 2008 CN modeling and the Rate Case forecast is indicative of the same or similar difficulties Xcel has had with budgeting in general. Xcel estimated in the 2008 CN for the ISFSI that the total cost, including licensing, for 2008 through 2034, was $155 million ($2008). Xcel's most recent cost estimate, solely of the dry cask storage without relicensing costs, is $355 million ($2015). What is not known at this time is what decisions would have been made had the 2008 modeling included the rate case forecast along with the increases in the entire LCM project budget for the period out to 2034. While Xcel may not have fully understood the changes taking place in the industry affecting the capital costs for the dry cask storage, Xcel should have at least run a sensitivity analysis including at least a 50% increase in the capital cost to account for uncertainties in forecasting. However, even had a 50% contingency been applied to the 2008-2034 total the resulting capital cost would not have been high enough to capture the higher costs of dry cask storage that Xcel currently expects. Therefore, Xcel underestimated drivers and magnitudes of the drivers impacting the dry cask storage project. [58]

Table 6: Dry Cask Fuel Storage (ISFSI)
Prairie Island Total Capital Expenditures

	Total (2008-2034)
2008 Certificate of Need	$155 million ($2008)
2012 Changed Circumstances Petition	$281.2 Million ($2015)
2015 Rate Case Filing	$361.2 Million ($2015)

Moreover, as discussed above, Xcel notified the Commission in its October 2, 2015 Resource Plan that Prairie Island costs for 2021-2034 are expected to be $600 to $900 Million, in addition

[58] Source: Combination of numbers provided by Xcel in IR 2155-A, which covers the years 2011 to 2034, and the 2008 to 2010 numbers from Docket No. E002/GR-15-826, Exhibit (SLW-1), Schedule 3, Page 1 of 2.

to the costs Xcel proposed to recover in its 2016-2019 rate case (which are shown in Table 1 above).[59]

[59] Xcel's October 2, 2015 filing at 13, Docket No. E002/RP-15-21.

SECTION 5.0 – XCEL'S RESPONSES TO CHANGES IN REGULATORY REQUIREMENTS OF THE NRC

Xcel provided details of the activities, decisions, and costs associated with the NRC compliance requirements for meeting the nuclear safety requirements proposed by the NRC's Near Term Task Force following Japan's Fukushima Dai-ichi Plant accident in 2011 and other compliance issues that have been identified by the NRC. Xcel estimated that, since 2008, changed in NRC's regulatory requirements totaled over $214.411, 340 million, as shown in Table 7 below. Global notes that only the items in bold italic, which add up to $121,601,703, appear to be attributable to the Fukushima accident for the period 2008-2015, based on the information available at this time. Also, while the items in bold italic in Table 7 could reasonably be attributed to the Fukushima accident for the period 2008-2015, Xcel should provide further information in their next rate case to demonstrate that the Company would not have undertaken such projects for ordinary LCM work, *but for* the NRC's requirements stemming from the Fukushima accident, and provide the NRC requirements to support that assertion.

Neither Xcel nor any of the U.S. nuclear fleet has any other recourse other than to fully comply with the NRC's compliance requirements coming from the "lessons learned" Fukushima review. The plants owners/operators such as Xcel have safety as their highest priority.

Since plant owner/operators must comply with NRC requirements with little recourse, it is important for Xcel to update the Commission and the Department for compliance costs, regularly. The NRC does not specifically stipulate the type of technology required for compliance with the specific requirements; however, the NRC does require the Company to submit their plan(s) for compliance for approval and further provides the NRC inspect the final deployed technology, procedure, or construction. Xcel is not required to submit budget or cost data to the NRC for compliance requirements. Therefore, it is important for Xcel to maintain communications with the Commission and the Department of the planned schedules, budgets, and completion dates. Global addresses this issue in RECOMMENDATION 1 below.

Table 7: List of Changes in NRC's Requirements 2008-2015[60]

NRC Compliance Requirement	**Code, Document, or Finding Requirement**	**Total Cost 2008 - 2015**
License Renewal	*NRC License Requirements & Commitments*	*$68,640,528*
Fire Protection	**NFPA 805 Requirements**	***$48,829,521***
External Events - Fukushima Requirements	**NRC 2011 & Related Orders**	***$42,863,248***
RCP Seal Re-Design	*NRC fire protection and Fukushima requirements*	*$16,509,657*
Physical Protection & Plant Security	**NRC 10 CFR 73 Requirements**	***$15,148,720***
Security - Force on Force	**NRC Security Inspections**	***$11,718,570***
Steam Generator Water levels	*NRC Regulatory Guide Section 1.97*	*$3,844,327*
Cyber Security	**NRC 10 CFR 73.74 Requirements**	***$1,999,533***
Emergency Requirements - Security & Diesel Backup	**NRC B.5.b Regulations**	***$1,042,111***
Spent Fuel Pool Protection	*NRC 10 CFR 50.54(f) Letter Requirements*	*$778,777*
Gas Venting	*NRC Generic Letter 2008-01*	*$649,542*
Battery Chargers	*NRC inspection finding*	*$893,228*
4KV Bus Modifications	*Commitment made in 2/3/14 response to NRC Request for Additional Information*	*$795,788*
Diesel Room venting	*NRC inspection finding*	*$570,000*
Diesel Transient	*Commitment made to NRC as part of License amendment for Tech Specs on voltage and frequency*	*$69,074*
Emergency Siren Narrowband	*FCC requirement - compliance due by Dec. 2012*	*$58,716*
Total Bold Italic Figures, 2008-2015		***$121,601,703***
Total Xcel-Identified Prairie Island Compliance Cost 2008 - 2015		$214,411,340
Difference		$92,809,637

[60] Scott Weatherby's Supplemental Direct Testimony, Docket No. E002/GR-15-826, SLW-1, Schedule 7, page 1.

Italicized entries indicate that Global verified the NRC Code, Finding, or Document Requirement. Items in bold are discussed further in Table 8 below, as to their expected costs for 2016-2020.

The budgeting and schedules regarding compliance with NRC requirements for Xcel appears to have been just as challenging as Xcel's schedule and budget responsibilities during the EPU and LCM projects. While Xcel must comply with NRC requirements, Xcel should provide clear and accurate cost estimates, along with identifying any licensing options and delays that can occur with the NRC, especially when new externalities such as the Fukushima accident and subsequent "lessons learned" compliance occur.

Unfortunately for Xcel, while the Company was wrestling with the EPU, LCM and License Extension, these compliance issues were also penetrating the NRC's areas of responsibilities, consuming time and resources for both the NRC and Xcel. However, with this said it is up to the Xcel Project Licensing and Compliance organization to maintain constant communications with the NRC in order to minimize schedule delays or at a minimum notify the Commission that these issues are causing delays. It is critical for Xcel's Licensing Team to be in constant contact with the NRC on a daily basis when timing is so critical. Typically, this need requires the Licensing Team to maintain constant communications even when there is not a compliance or licensing issue pending.

The areas highlighted and bold italic in Table 7 above are the most significant from the cost, schedule and the new or increased scrutiny perspective by the NRC. Each of these areas also has presented Xcel with challenges due to delays by both the NRC in carrying out their function and Xcel in responding in a timely manner to the NRC.

Xcel forecasted approximately $89 Million in continuing NRC compliance costs for the forecast horizon of 2016 – 2020. Table 8 below details these projects and their associated estimated costs.

Table 8: Xcel's Estimated NRC Costs for 2016-2020, Excluding AFUDC[61]

NRC Compliance Requirement	Code, Document, or Finding Requirement	Total Cost 2016-2020
Fire Protection	NFPA 805 Requirements	$51,432,064
External Events - Fukushima Requirements	NRC 2011 & Related Orders	$10,140,000
Security Upgrades including Cybersecurity	NRC 10 CFR 73 & Inspection Requirements	$9,852,989
Tornado Missile/Projectile Protection	NRC Regulatory Issue 2015-06	$7,000,000
16 KV Bus Modification	Commitment made in 2/3/14 response to NRC Request for Additional Information	$8,046,303
Steam Generator Water Level	NRC Regulatory Guide Section 1.97	$2,600,000
Total 2016 - 2020		**$89,071,356**

Global's analysis of costs, along with comparisons with information readily available through public sources and the NRC, indicates that Xcel's actual and estimated compliance costs for NRC requirements appear to be within reason. Actual costs for compliance-related activities can be difficult to benchmark other than to compare the magnitude of these costs, particularly for site-specific requirements such as site security including physical plant, force-on-force, and personnel. Cyber security has also become a challenge for nuclear plants as well as most everything in industry. Global notes that security may continue to be challenging from a cost perspective and intellectual technology for the foreseeable future.

[61] Scott Weatherby's Supplemental Direct Testimony, Docket No. E002/GR-15-826, SLW-1, Schedule 8, page 1.

SECTION 6.0 XCEL'S ESTIMATES OF COSTS FOR THE PRAIRIE ISLAND PLANT THROUGH 2034.

Xcel prepares its non-outage O&M budget much the same way many utility and non-utility industries prepare O&M budgets. The near term (5 years) is planned with the knowledge of the previous 5-year actuals and includes any specific project costs that may not be a recurring type of O&M cost. These 5-year budgets are reviewed or "truth tested" through iterations between functional areas of the plant that are responsible for managing these budgets and through the management of the nuclear organization itself. The longer term budgets are developed based on escalation of the annual budget amounts in the short term budget. Xcel's escalation rate in its 2015 rate case was approximately 4%.

O&M costs are typically driven by internal labor costs and external labor such as security and contract labor. Prairie Island has increased staffing to bring its overall staff levels to a position to provide needed regulatory and safety improvements, as well as increases in compensation necessary to attract, maintain and increase needed in-house staff. The Company is experiencing high levels of turnover particularly in senior positions. At the same time, the staff is aging towards retirement. In both cases Xcel is working diligently to attract new talent and to maintain their existing talent base. This is a particularly difficult situation in that experienced nuclear staff are not readily available unless incentives and competitive pay is offered to perspective employees. While Xcel is maneuvering to bring in talented staff, the industry is also looking for the same human resources creating an employment competition. In order to attract the necessary qualified employees to maintain Xcel's focus on its objectives of excellence in operations and safety they must be prepared to offer commensurate competitive pay, incentives, and signing bonuses. This competition for the narrowing talent pool drives the overall costs of compensation packages and retainer costs upward. Both of these drivers increase the O&M budgets and are likely to continue to do so over the next several years as the staff continues natural attrition.

Another driver of higher O&M costs over the forecast period is Xcel's goal to reduce its dependency on contract labor. This reduction in contract labor will likely produce upward pressures on O&M budgeting by increasing personnel and might appear to be counterproductive to the O&M budget. However, it is actually a good strategy in that over time it increases the overall nuclear knowledge base and capabilities within the Company, and reduces costs of overseeing contractors and costs of errors by contract personnel. This is one method to help avoid some of the competitive “bidding” for new staff outside the Company. At the same time the Company has goals to reduce overall O&M budgeting in order to control budgets. While these two conditions seem dipole opposite, developing the competencies of internal staff is necessary to provide for the future.

As can be seen in Table 9 below the two FERC Accounts (517 Operation Supervision and Engineering) and (528 Maintenance Supervision and Engineering) show the increases and decreases of these costs as the Company attempts to achieve the optimal staffing combination. Company witness Mr. O’Connor has stated his goal of achieving an overall O&M forecast increase that falls within a 0-2% range. However, it is also identified in DOC Information Request No. 1165; Docket No. E002/GR-15-826 that Xcel’s forecasted budget increases are normalized at 3.5% per annum for the period 2021 through 2033.

Table 9: Xcel’s FERC Form 1 Data on O&M Costs

Xcel Nuclear O&M Less Fuel - Ferc Form 1	2009	2010	2011	2012	2013	2014	2015	2016
Nuclear Power Generation	$0	$0	$0	$0	$0	$0	$0	$0
Operation	$0	$0	$0	$0	$0	$0	$0	$0
(517) Operation Supervision and Engineering	$55,496,919	$72,470,778	$66,751,510	$67,658,799	$77,206,977	$83,284,140	$68,885,785	$71,715,041
(518) Fuel	$92,085,127	$118,068,894	$112,372,793	$114,220,960	$108,436,237	$119,411,936	$106,424,403	$116,981,547
(519) Coolants and Water	$6,035,232	$6,928,264	$6,876,605	$7,350,896	$7,666,034	$8,334,095	$8,558,269	$8,674,239
(520) Steam Expenses	$35,549,432	$36,157,756	$43,337,565	$43,760,607	$46,620,207	$51,321,186	$48,558,925	$47,803,622
(521) Steam from Other Sources	$0	$0	$0	$0	$0	$0	$0	$0
(Less) (522) Steam Transferred-Cr.	$0	$0	$0	$0	$0	$0	$0	$0
(523) Electric Expenses	$2,173,923	$2,534,898	$1,958,149	$2,291,390	$2,813,977	$3,438,776	$2,181,969	$4,147,206
(524) Miscellaneous Nuclear Power Expenses	$112,945,299	$114,497,703	$122,474,603	$125,772,044	$132,354,514	$140,746,026	$137,686,669	$138,059,327
(525) Rents	$4,890,473	$5,205,609	$10,191,626	$9,735,275	$10,385,244	$10,473,975	$10,584,494	$10,763,466
TOTAL Operation (Enter Total of lines 24 thru 32)	$309,176,405	$355,863,902	$363,962,851	$370,789,971	$385,483,190	$417,010,134	$382,880,514	$398,144,448
Maintenance	$0	$0	$0	$0	$0	$0	$0	$0
(528) Maintenance Supervision and Engineering	$11,319,965	$10,634,078	$11,499,633	$12,674,357	$16,040,495	$12,742,279	$8,331,495	$6,647,149
(529) Maintenance of Structures	$478,277	$633,616	$604,460	$693,060	$599,086	$646,661	$685,835	$845,272
(530) Maintenance of Reactor Plant Equipment	$26,921,321	$19,499,095	$32,843,382	$32,093,358	$32,586,412	$39,220,988	$38,944,100	$42,572,905
(531) Maintenance of Electric Plant	$11,975,527	$25,963,285	$13,095,812	$12,197,466	$15,377,148	$19,309,349	$19,566,892	$17,491,413
(532) Maintenance of Miscellaneous Nuclear Plant	$22,493,682	$24,543,774	$27,926,343	$25,782,147	$29,320,834	$40,951,887	$44,402,887	$30,900,109
TOTAL Maintenance (Enter Total of lines 35 thru 39)	$73,188,772	$81,273,848	$85,969,630	$83,440,388	$93,923,975	$112,871,164	$111,931,209	$98,456,848
TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	$382,365,177	$437,137,750	$449,932,481	$454,230,359	$479,407,165	$529,881,298	$494,811,723	$496,601,296
TOTAL Power Production Expenses-Nuc. Power less Fuel	$290,280,050	$319,068,856	$337,559,688	$340,009,399	$370,970,928	$410,469,362	$388,387,320	$379,619,749

More specifically, as can be seen in Table 10, Actual non-fuel O&M ("Non-outage") has been running at approximately 5.5 % annualized over the 2009 to 2015 timeframe,[62] whereas the 5-year O&M Budget for 2016 through 2020 is approximately 1.7%, annualized.[63]

Table 10: Changes in Xcel's Actual and Forecasted O&M Costs from 2015 Rate Case

Operating & Maintenance (O&M) Expense													
	Actuals								5-year O&M Budget for 2016 Rate Case				
O&M - $ in millions	2008*	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Prairie Island Site O&M Expense:													
Non-outage	$103.4	$121.3	$129.5	$127.8	$128.1	$141.9	$152.7	$148.5	$147.3	$150.9	$154.8	$157.8	$161.4
Planned Outage - as Spent	$ 55.5	$ 35.3	$ 35.0	$ 27.1	$ 83.1	$ 56.0	$ 45.6	$ 46.6	$ 43.0	$ 40.6	$ 45.2	$ 41.1	$ 41.4
Subtotal - O&M Spend	$158.9	$156.6	$164.5	$154.9	$211.3	$198.0	$198.3	$195.1	$190.3	$191.5	$200.0	$199.0	$202.8
Outage (Deferral) Amortization*	$(39.9)	$ 0.7	$ 7.0	$ 11.9	$(26.7)	$ (9.6)	$ 8.4	$ 3.9	$ 2.6	$ 3.8	$ (3.2)	$ 1.5	$ (0.0)
Total O&M - Site	$119.0	$157.2	$171.6	$166.8	$184.5	$188.4	$206.7	$199.0	$192.9	$195.3	$196.8	$200.5	$202.8
		17.3%	6.8%	-1.3%	0.3%	10.8%	7.6%	-2.8%	-0.8%	2.4%	2.6%	2.0%	2.2%

Xcel's forecasted annual change in O&M costs in Xcel's 2015 IRP was an increase of 3.5 percent, more than twice as high as the 1.7 percent annual increase in the rate case.

Table 11: Xcel's Assumed O&M Costs from 2015 IRP*[64]

Operating & Maintenance (O&M) Expense Projections Used for 2015 IRP Modeling (in Future $)														
O&M - $ in millions	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034 (3)	Total 2021-34
Prairie Island Site O&M Expense:															
Non-outage (1)	167.0	172.9	178.9	185.2	191.7	198.4	205.3	212.5	219.9	227.6	235.6	243.8	252.4	130.6	$ 2,821.7
Planned Outage - as Spent (1)	42.9	44.4	45.9	47.6	49.2	50.9	52.7	54.6	56.5	58.5	60.5	62.6	64.8	-	$ 691.1
Total O&M Spend	$209.9	$217.3	$224.9	$232.7	$240.9	$249.3	$258.0	$267.1	$276.4	$286.1	$296.1	$306.5	$317.2	$ 130.6	$ 3,512.8
Outage (Deferral) Amortization (2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Total O&M Modeled for PI (2)	$209.9	$217.3	$224.9	$232.7	$240.9	$249.3	$258.0	$267.1	$276.4	$286.1	$296.1	$306.5	$317.2	$ 130.6	$ 3,512.8
	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%			

Notes:
(1) All projections above for the 2015 Integrated Resource Plan (IRP) were based on 3.5% annual escalations from the 2020 values in the 5-year budget used in the 2016 rate case.
(2) The estimated impacts of Outage deferral/amortization was not included in the O&M projections for the 2015 IRP, as Outage O&M was modeled on an as-spent cash flow basis.
(3) Unit 1's license expires in 2033 while Unit 2's license expires in 2034. Thus operating costs are assumed to be significantly reduced in 2034 with the shutdown of one unit, and no planned outages are assumed to occur after 2033.

[62] The average of the actual percentage changes in O&M costs for the period 2008 through 2015 (17.3%, 6.8%, -1.3%. 0.3%, 10.8%, 7.6%, -2.8%), shown in the last line of Table 8, is 5.5 percent.
[63] Similarly, the average of the budgeted percentage changes is 1.7 percent.
[64] Source: Xcel's response to information request 1165, Attachment B from Xcel's 2015 rate case, 15-826.

As Prairie Island continues to age the O&M budget will require continued focus to maintain a relatively slow overall growth. It would be helpful for Xcel to report annually on its actual annual costs for Prairie Island for fuel, other O&M and capital costs, compared to budgeted costs for each of these categories. This recommendation is included below.

An issue that has greatly impacted the O&M budget process is that of the "Third Party Inspections and Evaluations." These Third Party inspections take place on a regularly defined cycle (typically every 2 years). These Third Party inspections "drill down" much deeper into the safety, operations, personnel and risk management issues well beyond the level of the NRC inspections. For clarity sake, the NRC inspections are established to provide the licensee with a minimum level of review to assure safe and reliable operations. The Third Party inspections are established to provide the licensee with a guide to providing safe and reliable operations at a level of excellence. In each case, both inspections are necessary and help to assure that the plant and operations team meet a commitment to the Company, the regulatory community and the ratepayers. These inspections and the findings are to be taken seriously.

The Third Party inspections are performed by a team of highly knowledgeable professionals from the nuclear industry with no specific connection to the plant or the Company. In other words, this is an autonomous, independent inspection with a very strong focus on identifying problems and issues at the plant that are affecting the ability of the plant to perform at a continuously high level that would support a grading of excellent.

The linkage between the findings of the Third Party Inspectors and the O&M budget is one that is extremely difficult for anyone other than the Company to fully understand. As discussed above, the Third Party Reports are held very tightly to strict confidentiality agreements. As a result, the observed issue, the specific resolution and the cost of resolution are not available to the Commission or the Department unless the regulators request to review these reports and the Company's mitigation strategy. Not until this review has the Commission or the Department even been made aware of the importance of these assessments and reviews.

Most if not all of the issues exposed by the Third Party inspections directly influence the O&M budget. However, since these issues are so tightly controlled by the Company there is little specific information or documentation of what it costs the ratepayer as a result of the pressure on the O&M budget. The Third Party inspections may be very helpful to the utility by identifying challenges a utility has in addressing maintenance issues in a proactive and timely manner. The Third Party inspections are performed by inspectors who have similar responsibilities for other nuclear plants, thus providing specific perspectives that the utility may not have since its own personnel are focused on the operations of one plant.

In addition to the direct impact of the Third Party findings on the O&M budget, it was revealed that, in some cases, the failure of the organization to recognize problems, resolve conflicts, or possess the necessary training and skills resulted in unit deratings, or unit trips affecting the ability of the plant to produce energy. In such cases, the Company either had to utilize more expensive reserve units or to purchase additional resources on the short-term spot market. In either case, the resulting price of energy to the ratepayer was higher than it otherwise would have been had the Prairie Island units kept running. Regardless of the reasoning for the reduction in energy production, without a significant "fault-tree" analysis and subsequent cost analysis the effects of the lost energy could be a direct pass-through of costs to Xcel's ratepayers via the fuel adjustment clause. These issues tend to mount up over time and could create a significant budget variance that would be nearly impossible to track without prior knowledge of the Third Party review.

For example, the October 2015 Third Party Report identified that, in June 2014, Xcel manipulated valves in the wrong sequence, causing a feedwater transient while the unit was operating at power and requiring a reduction in load at the plant.[65]

To remedy such an occurrence fully, refresher training is required, possibly revisions to procedures, and certainly increased scrutiny of work during subsequent outages or preventative maintenance assignments. In addition, since the incident resulted in a load

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[65] In other words, Xcel's actions caused an abnormal change in the normal flow of feedwater while the plant was operating.

reduction there was loss of availability of Prairie Island, resulting in the need to find additional energy resources within the Company or from off-system purchases.

The Third-Party Inspectors' July 2017 inspection identified similar instances where outages of Prairie Island were due to oversights or errors by Xcel personnel. Examples included Prairie Island Engineers not preventing:

- a malfunction of the main feedwater regulator valve positioner because of lack of thoroughness in cause evaluation. This oversight resulted in the unit derating to 15% power (loss of 85% of power) for approximately 2.5 days;
- overheating on the Unit 1 Iso-phase Bus duct system due to inadequate grounding. This error resulted in the unit being derating to 50% power for 12 days.

In addition, in support of the discussion above regarding the need for greater clarity in Xcel's proposed costs for the LCM, the 2017 inspection identified an issue that appears to have its nexus as far back as the beginning of the LCM program and seems to have continued. Namely the 2017 Third-Party Inspection noted that Engineers have not submitted LCM plans for important systems, and therefore Long Range Plans are based on incomplete information.

These are a small set of issues chosen specifically to cast a bright light on the problems with overseeing Xcel's O&M and O&M budgeting.

The higher annualized O&M costs are not just to mitigate the findings in the Third Party reports but also include some of the LCM activities associated with the extended life process to allow the Prairie Island Units to operate out to 2033 and 2034, as well as general O&M necessary to maintain the plant operations. However, incorporated within these numbers are costs to address the Third Party findings. For example, Xcel's staff may have needed to invest time in responding to the particular observations and recommendations of the Third-Party Inspectors. However, the expectation is that such investments of time and resources would lead to lower costs in the future.

Global asked Xcel for clarity as to how much of these O&M costs are attributable to the Third Party findings. Global concludes, based on Xcel's responses to Information Requests No. 2138, that Plant Availability has steadily improved, O&M costs have decreased and the resulting benefit is the reduction of Power Costs to $29.69 in 2017, the lowest since 2010. These benefits evidently accrued as a result of the Company's commitment to performance standards and the results of the Third Party inspections. In other words, the benefits appear to be a result of synergies between internal Company-driven strategies and the Third Party inspections, which is how an aggressive internal and external strategy should benefit the Company and Ratepayers.

Global also notes the comment made by the Third Party Inspectors at the outset of their 2017 report, which supports and acknowledges that Xcel has made significant changes in policies and procedures to address the cultural difficulties of the past. Global agrees, based on the information we reviewed for this report. However, the Third-party Inspectors also noted that Xcel needs to do more to ensure that the Company's engineers identify risks early on and prevent such risks from becoming larger problems and that mid-level managers and supervisors need further development to address performance issues quickly and effectively to ensure that the Company performs consistently at high, effective levels.

The sheer number and magnitude or significance of the identified issues in the Third Party Report indicate that a significant level of O&M dollars is being focused on resolving these issues. As previously discussed, these dollars are above and beyond the forecast dollars typically considered in the budget forecasting process except for issues that may take more than a fiscal year to resolve. It does not appear from any documentation that Xcel has made the Commission or the Department aware of these issues and added costs during previous submittals. Therefore, the budget as reflected in filed documentation, IRPs or other formal processes may not identify these costs, causing continual budget variances from actuals due to the increased O&M costs.

Based on information received from Xcel, the actual magnitude of these variances is difficult to ascertain. Xcel indicated that there were no increases in O&M costs, but clearly the time that Xcel spent addressing the issues identified by Third-Party Inspectors meant that other

O&M work could not be done. Nonetheless, it is hoped that the work done in addressing the concerns identified by the Third-Party Inspectors will reduce future O&M costs, compared to what those costs might otherwise have been.

SECTION 7.0 CONCLUSIONS & RECOMMENDATIONS

CONCLUSION: Compliance costs typically are not costs that can be discretionary in the budgeting process. The NRC and Third-Party Inspectors are clear in their reports that issues that are elevated to the level of immediate response do not have an "either or clause" attached that gives the Company discretion to address or not. These costs are going to be necessary in order to maintain the operating license. Likewise, new security, cyber and force-on-force, are not discretionary either. For these reasons Global makes the following recommendation:

RECOMMMENDATION #1: Due to the nature of "compliance costs," their irregular timing, and the costs associated with these types of projects, Global recommends that there be established a mechanism whereby Xcel informs the Commission at the time of determination that a compliance issue is "discovered." At that point Xcel should submit to the Commission a non-binding project description, which includes project scope with specifics, compliance criteria, schedule, and budget. The project scope, compliance criteria, schedule, and budget should be updated with the Commission on an annual basis or sooner if significant changes warrant an update sooner than annually. Such reporting can be structured so that a project that is budgeted for more than $5 Million in any one calendar year or $10 Million in total cost must be reported. (These figures are for informational purposes only. They should be negotiated and agreed upon between Xcel and the Commission.)

By the time one of these projects reaches the operational stage it can be as many 10 years with multiple millions of dollars spent prior to any knowledge of accounting treatment within a rate case. The burden of proof to show that recovery of the costs would be reasonable would still be on Xcel, to be adjudicated in a formal rate case. While this recommendation is made with specific reference to compliance issues, it would also be a good idea if this level of documentation were to be provided for any nuclear capital project. This Recommendation could be formalized within the Commission's "changed circumstance" provision.

It may not be necessary for the Commission to take specific action on such filings. However, since nuclear costs are so high for any work and the history of the nuclear industry to meet budget and schedules is less than exemplary, the Commission and the Department could benefit to have this reporting on all nuclear projects. This information should be made available for any Prairie Island and Monticello projects.

CONCLUSION: The initial capital budget estimate for the EPU was $330 million. However, in this $330 million were projects that were defined as LCM and EPU. Also, the budget estimate was prepared well before any reasonable engineering design had been completed. As a result, the budget provided to the Commission and the Department was significantly confusing and impossible to track without being embedded within the accounting, engineering and operations functions of Xcel. As such, Global concludes that capital budgeting for major projects has been a challenge for Xcel both at Prairie Island and Monticello. In particular, the long lead-time capital projects appear to present the most problems. Global's analysis points to three critical failures of Xcel in their budgeting process.

1. Xcel brings to the Commission their application for CN well before they have considered detailed engineering design. Without an appropriate contingency to reflect the development level of the costs, Xcel's estimates of costs are grossly inaccurate. This issue was a problem for Monticello and Prairie Island. More and better attention to scoping of the capital projects and establishing more realistic schedules for filing with the Commission would greatly improve the accuracy of their cost estimating.
2. It is clear from the application for CN that Xcel continues to struggle with the use of proper contingencies in cost estimating. Perhaps Xcel feels compelled to provide cost estimates with the smallest contingencies because it helps to justify the project. However, such an approach would not be reasonable if it results in choosing projects that are not sufficiently scoped. It would be particularly concerning if the standard or practice were that, once the CN is approved any cost increases would be difficult to disapprove as long as it is within the original scope of the project that is too broadly stated.
3. In reality, given Xcel's low level of development of the proposed costs at the time of application for a CN, if the original budget had included a proper contingency it may have impacted the overall decision to move forward with the project or may have resulted in Xcel's projects not being selected as reasonable resources. However, the appropriate contingency would have provided a more accurate estimate of final costs.

<u>RECOMMMENDATION #2:</u> Global recommends that Xcel provide better written communications, documentation and appropriate contingencies to reflect the level of development of estimates for proposed projects, to assist the Commission and the Department to carry out their functions to protect the public interest, especially related to nuclear approvals and cost recovery analysis.

Nuclear costs by their nature are extremely expensive and the schedules for deployment can be affected by external factors such as the earthquake and subsequent tsunami and nuclear accident that occurred in Fukushima, Japan and affected the NRC approval process. Thus, Xcel must engage in a more transparent reporting process to provide reasonable information for the Commission's and the Department's knowledge.

Specifically, Global recommends that Xcel's policies and procedures be modified to require Xcel to present initial budget estimates in CN dockets only after a minimum of 60% engineering design has been completed. Correspondingly, budget estimates should have a minimum of 50% contingencies in the budget and this 50% contingency should be included in all financial pro forma's and planning models. Such an approach would provide for a more reasonable estimate of costs and expose Xcel and its ratepayers to less risk of cost increases due to factors that are within Xcel's control, namely gaining a better understanding up front about project scope.

In addition, if, in the execution of the project, there is a 15% change in the budget estimate or a schedule delay that may cause upward pressure on the budget, Xcel should be required to file a revised budget with full and concise explanation of the causal actions and the resultant impacts. The objective of this recommendation is to have a fully informed Commission and Department throughout a capital initiative, not just at the time of rate case docket.

Global notes that Xcel appears to have partially addressed this issue through the addition of personnel more familiar with cost estimating and project scope definition. Global supports these changes.

CONCLUSION: Xcel refers to numerous benchmarking studies and comparison studies it employs during various stages of projects and regulatory filings. Benchmarking can be an extremely helpful tool if used correctly and if the results are understood within the framework of the benchmark analysis. However simply benchmarking against a set of costs or a set of work products may not be helpful or even accurate unless the benchmark is against similar base data with similar operating characteristics and goals. Xcel refers to these benchmarks almost as if they are indicative that Xcel is doing all the right things. However, such benchmarking provides little useful information without disclosure of all relevant underlying facts. For example, a benchmarking study result is sensitive to the method of retrieval of data, the definition and size of the population of the benchmarked subject (in this case, industry pressurized water reactor nuclear plants), the regulatory requirements and other factors.

Moreover, benchmarking does not absolve Xcel of its responsibility to demonstrate that any cost overruns are reasonable to charge to ratepayers. If Xcel chooses to use any benchmarking studies to justify or support their efforts, Xcel must also provide all relevant underlying facts affecting costs of such facilities to the Commission and Department for validation and for any meaning to be ascribed to such studies.

RECOMMMENDATION #3: If Xcel provides any *Benchmarking Study* to attempt to justify their performance, the Commission should at a minimum require the Company to produce complete copies of such studies and supporting documentation before giving any weight to the information. No benchmarked results should be accepted as accurate or representative without collaboration by the Commission and the Department.

CONCLUSION: Considerable capital expenditures have or will accrue to Xcel as a result of the LCM and some small costs associated with the now abandoned EPU, as well as on-going safety and reliability projects necessary for normal plant operation during the extended license period. These capital costs will position Prairie Island to operate until 2033 and 2034, the expiration of the extended license. What will happen to Prairie Island at that point in time is unknown. For example, the method of decommissioning has yet to be determined. Further, focusing solely on the NRC, if Xcel were to request a second life extension, beyond 60 years of operation, it is not known whether the NRC would allow a second extended license if such a request were made. There is no history or experience with the licensed operators and the NRC to forecast the scope of such an undertaking. These questions do not begin to address other issues connected with any such life extension.

For example, solely from a technical perspective, it is unclear how the 60 years of operations will have impacted the Prairie Island infrastructure and whether the structural integrity would be of such a condition to support a second license extension. Similarly Monticello will reach the end of its license life in 2030 and there will be the same kinds of questions. Between now and then, it will be necessary for Xcel to determine whether it would be reasonable to request a second life extension from the NRC for any of the nuclear power units and it will be necessary for the NRC to determine the safety, integrity and reasonableness as to whether to grant any such life extension requests.

At the same time, it will be necessary to assess appropriate courses of action if Xcel does not request or the NRC does not grant second life extensions for any or all of the three nuclear generation facilities. It is expected that discussion of some of these questions will occur in Xcel's upcoming 2019 integrated resource plan. These questions need to be addressed in the near future. As of 2019, there are only 11 years from needing to have a solution implemented for Monticello, 14 years for one unit of Prairie Island and 15 years for the other unit of Prairie Island. It is likely to take longer than 10 years for the NRC to address the technical details of this issue in any detail for any nuclear facility for which Xcel may request a second life extension. As noted above, other issues connected with any such life extension would need to be addressed as well. Therefore, Global offers the following recommendation.

RECOMMMENDATION #4: Xcel's upcoming integrated resource plan is the first such planning period to extend beyond 2030, as it should cover the period 2019 through 2034. Thus, Xcel will need to approach this planning process to determine 1) whether a second life extension for some or all of the nuclear generation facilities is the best alternative for the Xcel generation fleet; 2) what alternative(s) would there be to Prairie Island 1, 2 or both; 3) would the NRC approve of another life extension and what analysis and filing requirements would be necessary; 4) if the NRC would approve of a further extension of life what would Xcel have to do to gain NRC approval; and 5) what issues would need to be addressed locally if there is any additional life extensions requested. Xcel should address such questions in its upcoming resource plan and should maintain clear communications in this process.

CONCLUSION: Global's review of the Third Party Inspection Reports and the latest NRC Integrated Inspection Report dated November 28, 2017 indicates that there have been material issues with the cultural identity regarding work performance and compliance. In general, Global's findings memorialize a number of critical issues and concerns identified by the Third Party Inspector concerning operating culture and management directions at Prairie Island. Nonetheless, Global notes that, while these two reports covered the 2015 inspection and the 2017 inspection, the Third Party Inspectors noted significant improvements from 2015 to 2017.

It does appear from Global's one-on-one interviews with Prairie Island managers in April of 2017 and with the conclusions in the Third Party reports that Xcel has taken a strong approach to abating the issues of the past and moving forward with skills training, addressing employee technical abilities, instilling responsible workplace habits, and engaging all employees, both Xcel and Contract, with an appreciation for "ownership" in plant operations and safety. The overall success of Xcel's programs will take time to fully appreciate the success and effort and the benefit to Xcel and the Minnesota ratepayers.

While Global supports Xcel's improvements to date, there is still a significant level of improvement necessary to return Prairie Island to a level of Excellence rating. Each identified issue in the Third Party Reports must be addressed and resolved in order for the Prairie Island plant to return to a position of Excellence within the industry nuclear fleet.

As discussed above, the importance of understanding the results, conclusions, and recommendations of the Third Party reviews directly impacts the O&M Budget for Prairie Island, not simply the safety responsibilities. Typically, these issues are unknown to the Commission or the Department because they are developed within a confidential environment.

For example, while the Third Party inspectors were clear to point out Xcel had progressed significantly from previous inspections to improve the operating performance of staff and labor, there continue to be concerns and recommendations for improvements. Xcel has accepted these recommendations and is moving forward at a strong pace to resolve the concerns. However, in the time since Global's review of the Third Party Reports the NRC published a November 28, 2017 NRC Integrated Inspection Report identifying several items, four of which are summarized below. While none of the results were classified as "a finding" or constituted a significant safety issue they nevertheless are noteworthy simply as an indicator of continuing issues with appropriate monitoring and training. The following are the most noteworthy issues identified — to Xcel's credit three of the issues were self-reported.

Prairie Island —3rd quarter inspection report—1 finding, non-cited; 3 Xcel findings, all non-cited.

a. Meteorological tower procedures did not include removal of trees that could impair the correct operation of sensors.
b. Xcel failed to provide an alternative shutdown capability for 17 Valves credited in the Shutdown Analysis that could have been rendered unavailable for manual operator action following a postulated fire in the control or relay rooms.
c. Xcel failed to assure that testing required to demonstrate that three safety injection system actuation relays would perform satisfactorily in service was identified and performed in accordance with written test procedures (that is, three safety injection system actuation relays had not been tested following replacement during planned maintenance.)
d. Control room operators did not evaluate Unit 2 'A' Component Cooling, Auxiliary Feedwater, and Cooling Water supported system limiting condition for operations (LCO) while the 121 Safeguards Chilled Water support system LCO was not met. As a result, the appropriate Conditions and Required Actions were not entered during Unit 2 'B' Component Cooling and Auxiliary Feedwater supported system maintenance and testing activities for which a loss of safety function existed.

These issues, in and of themselves, do not constitute any type of serious concern for immediate plant safety but do continue to expose the necessity for Prairie Island management and personnel to keep a close vigil on all policies and procedures and to make certain that personnel are up to speed with training and implementation of the policies and procedures.

RECOMMMENDATION #5: As the future unfolds for Prairie Island, it is recommended that Xcel maintain a more proactive communications path with the Commission and the Department. Over the years, Xcel has not identified the issues or resolutions of issues raised by the NRC and the Third Party Inspectors. Instead, the Company has requested recovery of higher costs from ratepayers, without adequate justification.

Xcel entered into a contractual relationship with ratepayers at the time of the approval and construction of Prairie Island 1 & 2 that effectively established that Xcel would provide for the safe and efficient operation of Prairie Island 1 & 2 to provide electric power at reasonable costs. However, it is clear that Xcel exceeded those costs, as identified in Table 1 above. The history of these projects is that Xcel did not conduct reasonable due diligence on behalf of ratepayers at the time of the CNs (e.g. not fully analyzing the cost-effectiveness of low pressure turbines as discussed above) and did not include contingencies to reflect the low level of analysis of the Prairie Island projects.

This information, along with the findings of the NRC and the Third Party Inspectors emphasizes that Xcel's cultural paradigm at that time was not fully supportive of Xcel's long-term goals to provide reliable service at reasonable rates. It appears that Xcel is in the process of changing that culture, yet more work is needed. As such, Global concludes that Xcel will need to demonstrate in the future why ratepayers should pay for either higher capital or higher O&M costs, especially those directly attributable to the resolution of the issues identified by the NRC and the Third Party Inspections. These issues need not be addressed at this time, but should be addressed in any future rate proceeding.

Finally, as discussed above, this report provided further clarity about costs of the Prairie Island plant, but more information would be helpful for future proceedings. As noted above, it would be helpful for Xcel to identify the components of Xcel's estimated $187 million in costs that were avoided due to not proceeding with the EPU. Xcel identified $66 million in avoided costs in its 2013 rate case, so identifying the components of the remaining $121 million in avoided costs would provide a better understanding regarding the costs of Prairie Island for its remaining life.

In addition, while Global confirmed that some of the components listed in Tables 7 and 8 above could reasonably be attributed to improvements stemming from the Fukushima accident, Xcel should provide further information in their next rate case to demonstrate that the Company would not have undertaken such projects for ordinary LCM work, *but for* the NRC's requirements stemming from the Fukushima accident, and provide the NRC requirements to support that assertion.