STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

XCEL ENERGY'S
REPLY BRIEF

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I. INTRODUCTION

Xcel Energy respectfully submits this Reply Brief in response to the post-hearing briefs filed by the Department, the OAG, and XLI. Each of these Parties seeks a material disallowance of the costs we incurred in connection with the LCM/EPU Program that will substantially impair a valuable asset that is providing customers cost-effective carbon free energy. These parties make two basic arguments in support of their respective requested disallowances: (i) the Company underestimated the cost of the Program on the front-end; and (ii) the Company failed to satisfy its burden of proving the prudence of its decisions and actions in developing and implementing the Program.

These two arguments are supported primarily by the generalizations offered by the Department's two consultants – who did not find imprudence – and facts peripheral to the Program that did not impact Program costs. They form a highly rhetorical and lightly factual argument supporting disallowance of Program costs and reflecting the general view that since the Program costs roughly doubled there must be imprudence. We can understand the appeal of such a simplistic view, especially, when we reflect upon the fact that this is likely the largest cost increase in the State's history. But this approach fails to account for the evolution of a ten-year effort and the changing circumstances that impacted Xcel Energy and our peers who embarked on similar initiatives, with similar results, during this same period.

There is general agreement that the purpose of this proceeding is to apply the prudent investment standard to the evidence on this record. When that is done appropriately, it means a careful and through review of all record evidence. It requires an assessment of whether the Company's decisions fell within a zone of reasonableness. That standard focuses on how we managed the Program and responded to the challenges we faced. When viewed from this perspective, the evidence that the Company produced about how it managed the Program, the alternatives we considered and why we made a variety of the decisions that we did, should become the focus of the ALJ's and Commission's review. Likewise the criticisms of these decisions should be viewed from the lens of whether or not there were clear alternatives that would have been superior and would have led to lower costs. Absent this, the Company should be allowed to recover the costs of the capital we deployed for this effort.

To be clear, this does not mean we are asking to hide behind a technical application of the law to the facts. Rather, we believe that the record is replete with evidence of prudent decision-making and project management at all stages of the Program. There were certainly bumps throughout, but every major construction project faces these. While we acknowledge the validity of certain arguments as to what drove our costs to increase, we do not believe that any of these prove anything more than that there were legitimate reasons why our costs did increase. What is missing from the record is any evidence that we did not follow industry norms; that our results fell well outside of others in the industry during the same time frame; or that we did not design and construct a Project that will serve customers well over the long run. In short, what is missing is evidence of imprudence.

In contrast, the Company's presentation about our processes for project management, design review, and quality assurance program that were deployed throughout the Program was thorough. We provided detailed factual explanations of what we spent on the LCM/EPU Program and, more importantly, why we spent it, why the costs increased, why those costs were reasonable and unavoidable, and how our implementation was, overall, reasonable. We also addressed the decisions we made, the approach we took, and our proactive management. Lastly, we discussed alternatives the Company faced at various junctures and explained why we made our decisions. Thus, we satisfied our burden to show our actions were prudent.

For these reasons, the Company respectfully disagrees with the Department, OAG, and XLI, and asks the ALJ and Commission to conclude that the Company prudently incurred the Monticello LCM/EPU Program costs.

For purposes of this Brief, the Company has structured its reply by issue rather than by Party since the Department, the OAG and XLI cover substantially overlapping issues. The remainder of this Reply Brief addresses the following issues:

- Legal Standard and Burden of Proof
- Substantial Credible Evidence Supporting Company's Position
- Reply to Specific Criticisms:
    - Decisions to Pursue Program;
    - Initial Planning and Design;
    - Project Management Criticisms;
    - LCM/EPU Split;
    - Unrelated Performance Criticism by Department; and
    - Weighing the Evidence
- Proposed Remedies
- Cross-References on the Department's Issues List
- Conclusion

II. ARGUMENT

The common theme that runs through the Parties' Initial Briefs is that costs went up; therefore, something must have gone wrong that calls for a remedy. The record, however, does not support this claim. Rather, the record demonstrates that the Company established the reasons costs increased and why our costs, while more than initially estimated, were reasonable. The Company provided thousands of important contemporaneous documents, objective accounting data, and hundreds of pages of detailed analysis and supporting schedules to illustrate and describe why the costs increased beyond our expectations. Not only did this probative evidence establish a *prima facie* case that our costs were reasonable, but as we explained in our Initial Brief and explain here, that we met our ultimate burden of proof.

A. Legal Standard and Burden

All of the Parties discuss the applicable standard for this proceeding. We agree with some of that discussion. For example, we agree that the prudent investment standard considers whether the utility's decisions or actions were reasonable (i) at the time they were made and (ii) under the circumstances that were known or reasonably should have been known at the time.[1] We also agree that the Company bears the burden of proving that all costs we propose to include in rates are just and reasonable.[2] We further agree that Minnesota law generally does not recognize a rebuttable presumption of prudence in matters of ratemaking, although we maintain that in the current circumstance the law should recognize that utility managers are presumed to act in good faith and prudently under the circumstances presented.[3] With that said, we respectfully disagree on several important aspects of the Parties' positions.

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[1] Department Initial Br. at 1; OAG Initial Br. at 7; XLI Initial Br. at 3-4.

[2] *In re N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).

[3] See Xcel Energy Initial Br. at 16 n.27.

1. Prudent Investment Standard Revisited

Even though there is no dispute that this is a "prudence" investigation, the Department, the OAG and XLI raise "concerns"[4] and suggest problems that "likely" existed with various Company decisions and actions, relying heavily on the Department's investigators' commentary. Although the investigators did not reach conclusions about prudence, the Parties extrapolate that the concerns they raised call for imposition of a remedy whether or not imprudence is found.

Given this approach, it is important to reiterate that the standard does not require perfection or allow for hindsight or second-guessing.[5] It does not erect an impenetrable wall, defeated merely by a Party saying our case was 'not good enough.' Our conduct need only fall within a "zone of reasonableness" to justify recovery:[6]

> The term "prudent investment" is not used in a critical sense. There should not be excluded, from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures.[7]

"The focus in a prudence inquiry is not whether a decision produced a favorable or unfavorable result, but rather whether the process leading to the decision was a logical one, and whether the utility reasonably relied on information and planning techniques

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[4] XLI Initial Br. at 3 ("The Department's Prudence Review Investigation Revealed Significant Concerns about NSP's Planning and Management of the Monticello Project.").

[5] *In re GPU, Inc.*, 96 Pa. P.U.C. 1, 91-92 (Pa. PUC 2001); *In re Long Island Lighting Co.*, 24 N.Y.P.S.C. 4921 at *6 (Aug. 19, 1981); *Pa. Pub. Util. Comm'n v. Philadelphia Elec. Co.*, 71 Pa. P.U.C. 42 (Pa. PUC 1989) (noting that the commission "must assess the reasonableness of a utility's decision-making based on the state of information available when decisions had to be made and without reliance on hindsight.").

[6] *See Fed. Power Comm'n v. Conway Corp.*, 426 U.S. 276, 271, 278 (1976).

[7] *Mo. ex. rel. Sw. Bell Tel. Co. v. Pub. Serv. Comm'n of Mo.,* 262 U.S. 276, 290 n.1 (1923) (Brandeis, J., concurring); *see Application of Peoples Natural Gas Co.*, 389 N.W.2d 903, 908 (Minn. 1986) ("Reasonableness is a concept of some flexibility and moderation, not exclusivity; a determination that one course of conduct is reasonable is not a determination that any other course is unreasonable.").

known or knowable at the time."[8] As such, it is not sufficient for a Party to assume an action was imprudent because it increased costs. It is for this reason that any disallowance must be supported by evidence establishing that imprudence caused actual harm to ratepayers.[9] In other words, in a prudence investigation it is necessary to establish both that (i) imprudence occurred and (ii) it caused harm.

These requirements have been borne out in multiple state prudence investigations. In *Violet v. Federal Energy Regulatory Commission*,[10] for example, the court found "the absence of more tangible evidence of a causal link between the allegedly imprudent contract and the costs" to be significant.[11] Likewise, in *Associated Natural Gas Co.*,[12] the court reversed a disallowance as unsupported because the commission did not find a causal nexus between the imprudence and the alleged harm.[13] And in *In re San Diego and Electric Co.*,[14] the California Public Utilities Commission rejected imposing a disallowance because the intervenor was "like a plaintiff in a personal injury action who has proved liability but has presented no evidence on damages" caused by the imprudence.[15] We will discuss many situations where the intervenors either ignore the need to create a causal connection or simply speculate there may have been one.

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[8] *Gulf States Utils. Co. v. La. Pub. Serv. Comm'n*, 578 So. 2d 71, 85 (La. 1991) (citing *Metzenbaum v. Columbia Gas Transmission Corp.*, Opinion No. 25, 4 FERC 61,277, 26 P.U.R.4th 144 (1978)).

[9] *See Potomac Elec. Power Co. v. Pub. Serv. Comm'n of the Dist. of Columbia*, 661 A.2d 131, 141-42 (Ct. App. 1995); *State ex. rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n of the State of Mo.*, 954 S.W.2d 520, 530 (Mo. Ct. App. 1997) (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers); *In re New England Power Co.*, Opinion No. 231, No. ER82-703-000, 31 FERC 61,047, 61,089 n.38 (Apr. 11, 1985) (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers)).

[10] 800 F.2d 280, 283 (1st Cir. 1986).

[11] *Violet*, 800 F.2d at 283.

[12] 954 S.W.2d at 522-23.

[13] *Associated Natural Gas Co.*, 954 S.W.2d at 530.

[14] 31 C.P.U.C.2d 236, 253 (Cal. Pub. Utils. Comm'n 1989).

[15] *In re San Diego and Electric Co.,* 31 C.P.U.C.2d at 253.

2. Burden of Proof

There is no dispute that the utility bears the burden to prove its costs included in rates are reasonable. Specifically, the burden involves the Company coming forth with evidence both that it actually incurred the costs in question and that those costs were reasonable. There is no dispute that the Company incurred its costs. And just as importantly, the Company's substantial and detailed body of evidence explaining the reason for cost increases satisfied our burden of proving the reasonableness of those costs.

With that said, we disagree that the applicable burden of proof means the Parties can simply disagree with the Company's decisions and actions in order to defeat the Company's burden of proof. Claims of imprudence must be supportable by specific record evidence and must tie to actual harm caused by imprudence. Blocking recovery simply by disagreement raises serious due process concerns. Once the Company provides a *prima facie* case that its decisions and actions were reasonable, fundamental fairness requires that the Commission review that evidence and weigh it against contrary record *evidence* to support its decision.

As a result, the Department's,[16] OAG's,[17] and XLI's,[18] reliance on the Minnesota Supreme Court's decision in *In re the Petition of Northern States Power Co. for Authority to Change its Schedule of Rates*,[19] is inapposite. In that case, NSP argued that "by proof of its actual capital structure, there arose a "rebuttable presumption of reasonableness."[20] The court disagreed, noting that "by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of

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[16] Department Initial Br. at 15-16.

[17] OAG Initial Br. at 8.

[18] XLI Initial Br. at 2-3.

[19] 416 N.W.2d 719, 723 (Minn. 1987).

[20] *In re the Petition of N. States Power Co. for Auth. To Change its Schedule of Rates*, 416 N.W.2d at 723.

demonstrating that it is just and reasonable that the ratepayers bear the costs of those expenses." The issue, then, was whether merely showing costs were incurred was sufficient to establish the reasonableness of those costs.

Here, the Company is not arguing that because we actually incurred Program costs those costs are presumptively reasonable. Rather, the Company contends that it established a *prima facie* case – and ultimately satisfied its overall burden of proof – by providing a body of important evidence *specifically with respect to reasonableness*. Fundamental fairness and the nature of a contested case proceeding require Parties to rebut competent evidence of reasonableness to overcome our *prima facie* case.

a. Balancing Interests

In focusing on the Company's ultimate burden of proof, the Parties note that "any doubt as to the reasonableness of rates 'should be resolved in favor of the consumer,'"[21] but ignore the preliminary principle that rates are just and reasonable only when they properly balance the interests of both the utility and customers. Indeed, the Commission's obligation in considering whether rates are just and reasonable is "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers…."[22] This balancing must occur *before* it can be determined whether there is a doubt to be weighed.

Balancing interests is not unbounded, and Minn. Stat. § 216B.03 does not create an automatic override of other interests. We respectfully submit that the Commission may not lose sight of the other important interests involved.[23] In particular, it is important for utilities to recover the costs of service with a return on that investment:

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[21] *See, e.g.*, OAG Initial Br. at 6; XLI Initial Br. at 2; Department Initial Br. at 15.

[22] *In re Request of Interstate Power Co. for Auth. to Change Its Rates For Gas Serv.*, 574 N.W.2d 408, 411 (Minn. 1998).

[23] *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n*, 302 N.W.2d 5, 10 (Minn. 1980) ("In considering these factors, the PSC must balance the interests of the utility against the interests of the utility's customers."). The *Hibbing Taconite* court went

> The rates charged subscribers are thereupon authorized in an amount which will equal the sum of the return to investors and the company's operating expenses.[24]

Cost of service has been recognized as a key element that must be included in just and reasonable rates, and as an objective standard.[25] Section 216B.03 does not provide a "trump card" or override the Commission's duty to balance the interests of all stakeholders.[26] In *Hibbing Taconite*,[27] the Supreme Court expressly rejected the notion that Minn. Stat. § 216B.03 eliminated the Commission's obligation to set a just and reasonable rate based on the evidence and record.[28] In *Minnegasco*, the Supreme Court found that the basis for rate-setting is "cost" and rejected an argument that Section 216B.03 overrode other standards.[29] These principles remain relevant here.

b. Burden of Persuasion and Burden of Production

Furthermore, the burden of proof has two important aspects: "the burden of persuasion and the burden of producing evidence."[30] The burden of persuasion is

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on to describe how the U.S. Supreme Court established requirements and constraints for setting just and reasonable rates and that the Commission must abide by such constraints. *Hibbing Taconite Co.,* 302 N.W.2d at 10.

[24] *Hibbing Taconite Co.,* 302 N.W.2d at 10 (quoting *Nw. Bell Tel. Co. v. State*, 216 N.W.2d 841, 846 (1974)).

[25] *N. States Power v. Minn. Pub. Utils. Comm'n*, 344 N.W.2d 374, 378 (Minn. 1984), *cert. denied*, 467 U.S. 1256 (1984) ("In order to establish "just and reasonable" retail rates, the MPUC must consider the right of the utility and its investors to a reasonable return, while at the same time establishing a rate for consumers which reflects the cost of service rendered plus a "reasonable" profit for the utility. . . . To accomplish this purpose, the MPUC must ascertain the operating expenses, or cost of service, of the utility.") (citations omitted); *see Minnegasco v. Minn. Pub. Utils. Comm'n*, 549 N.W.2d 904, 908-09 (Minn. 1996).

[26] *Hibbing Taconite Co.*, 302 N.W.2d at 10.

[27] *Hibbing Taconite Co.*, 302 N.W.2d at 9-11 ("Chapter 216B gives to the PSC the duty as well as the power to set a just and reasonable rate after a full review of evidence and testimony.").

[28] *See N. States Power Co.,* 344 N.W.2d at 378-82 (ratepayer protection theory rejected and Commission was required to allow utility to recover specified costs).

[29] *Minnegasco*, 549 N.W.2d at 909. ("In setting just and reasonable rates, the MPUC must give 'due consideration to the public need . . . for revenue sufficient to enable it to meet the cost of furnishing service . . . .' [Minn. Stat.] § 216B.16, subd. 6.").

[30] 11 Minn. Prac., *Evidence* § 301.01, at 128 (2012). *See Schaffer ex. rel. Schaffer v. Weast*, 546 U.S. 49, 56 (2005) (determining which party bears the burden of proof in an administrative hearing); *Stockton E. Water Dist. v. United States*, 583 F.3d 1344, 1360 (Fed. Cir. 2009) ("When dealing with burdens of proof it is essential to distinguish between two distinct burdens, the burden of persuasion and the burden of production (sometimes described as the burden of going forward)").

"the duty of creating an affirmative belief on the part of the tribunal in the existence of the fact or facts in issue."[31] It is generally fixed before the hearing and does not shift.[32] However, the burden of persuasion "is met by a *prima facie* case if no evidence to rebut it is offered," and "[a]n unimpeached *prima facie* case should prevail as a matter of law."[33] This rule applies both in administrative proceedings and civil cases.[34]

> A *prima facie* case shifts to the opponent of the one having the burden of proof, the burden of producing evidence to overcome it.[35]

The other party must produce evidence to rebut the *prima facie* case.[36] That evidence must be competent and probative[37] and not merely conclusory. The requirement to produce evidence is the burden of production.[38] It is "the duty of introducing evidence at a particular stage of a trial – of going forward with the evidence."[39]

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[31] 21 Dunnell Minn. Digest, *Evidence* § 13.01, at 286 (5th ed. 2006); *see Tech. Licensing Corp. v. Videotek, Inc.*, 545 F.3d 1316, 1326-27 (Fed. Cir. 2008) (defining the burden of persuasion as "the ultimate burden assigned to a party who must prove something to a specified degree of certainty").

[32] *See, e.g.*, Minn. R. Evid. 301 (shifts "the burden of going forward with evidence to rebut or meet the presumption, but does not shift to such party the burden of proof in the sense of the risk of nonpersuasion, which remains throughout the trial upon the party on whom it was originally cast."); *Commercial Molasses Corp. v. N.Y. Tank Barge Corp.*, 314 U.S. 104, 110-11 (1941).

[33] 21 Dunnell Minn. Digest, *Evidence* § 13.03, at 290 (5th ed. 2006); *see Fidelity Bank & Trust Co. v. Fitzimons*, 261 N.W.2d 586, 590 (Minn. 1977) ("[w]here a plaintiff proves a prima facie case and it is unrebutted by defendant, the plaintiff has met his burden of proof"); *Elk River Concrete Prods. Co. v. Am. Cas Co. of Reading, Pa.*, 129 N.W.2d 309, 314 (1964) (holding that the prima facie case had been met and the burden of proof going forward switches to the defendant); *Bass v. Ring*, 299 N.W. 679, 681 (1941).

[34] *E.g.*, *Rydberg v. Goodno*, 689 N.W.2d 310, 313-14 (Minn. Ct. App. 2004) (in administrative proceeding "at this point, the burden shifted to the parties opposing pass-eligible status"); *In re Chicago Rys. Co.*, 175 F.2d 282, 289-90 (7th Cir. 1949), *cert. denied*, 338 U.S. 850 (1949) (in court the "absence of explanatory or contradictory evidence" means "the finding shall be in accordance with the proof establishing the prima facie case").

[35] 21 Dunnell Minn. Digest, *Evidence* § 13.03, at 289.

[36] 21 Dunnell Minn. Digest, *Evidence* § 13.03, at 289; 73B C.J.S. Public Utilities § 131; *Gulf States Utils. Co.*, 578 So. 2d at 85; *Tex. Dept. of Comm. Affairs v. Burdine*, 450 U.S. 248, 252-56 (1981).

[37] *LaFavor v. Am. Nat'l Ins. Co.*, 155 N.W.2d 286, 291 (1967) ("[w]hile the evidence in proof of a crucial fact may be circumstantial, it must not leave it in the field of conjecture").

[38] *See, e.g.*, IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER APPROVING EXPENSES INCURRED FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012 THAT ARE RECOVERED THROUGH THE ELECTRIC COMMODITY ADJUSTMENT CLAUSE . . . ., No. R14-0496 in Proceeding No. 13A-0869E (May 9, 2014) (Uncontested ALJ Decision) ("*In re Public Service . . .*"):

This shifting of burdens is necessary for the contested case proceeding to have meaning. If a Party could defeat the Company's evidence showing the reasonableness of its decisions and actions simply by casting doubts – or by questioning the Company's actions without identifying whether the party's suggested alternative courses of action were feasible or would result in a different outcome – there would be no purpose in requiring prefiled testimony or evidentiary hearings.[40] Put simply, requiring parties to overcome competent evidence is not only common to all manner of adversarial proceedings; it is critical to satisfy due process considerations and avoiding confiscatory utility rates.

B. Substantial Credible Evidence

1. The Company's *Prima Facie* Case

The Company provided substantial evidence and testimonial explanations regarding all aspects of our performance. The Company made the type of detailed presentation expected to address Plant needs,[41] cost drivers,[42] project planning,[43] project

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> The burden of proof and the burden of going forward are on the Applicant in any application. The initial burden is met by the Applicant with the filing of testimony and exhibits in support of the application. After this filing, the burden of going forward, not the burden of proof, shifts to the intervenor to contest the prudency of any or all of the actions of the Applicant. … An Intervenor must state the specific actions that are not prudent. If the evidence is sufficient to bring into question the prudence of actions taken or not taken by the utility, the burden of going forward then shifts back to the utility to show that the questioned action or lack of action was prudent.

[39] 21 Dunnell Minn. Digest, *Evidence* § 13.01, at 386. *See Tech. Licensing Corp.*, 545 F.3d at 1327; *Ryan v. Metro. Life Ins. Co.*, 289 N.W. 557, 560 (1939) (discusses differences between burden of producing evidence and persuasion).

[40] In a somewhat analogous circumstance, the utility met its burden of proof where it provided an initial filing and exhibits supporting its requested cost recovery and the intervenor did not "state what action or inactions taken or not taken by Public Service led to the higher than average forced outage rate":

> There was no correlation between the forced outages and any imprudent actions or inactions by Public Service. There was only the naked conclusion that the forced outages could only be due to imprudent actions; no evidence was presented linking the two.[40]

In re Public Service, No. R14-0496.

[41] *E.g.*, Ex. 19, O'Connor Rebuttal at Schedule 6 (Certificate of Need Application for Independent Spent Fuel Storage Installation from January 2005 showing a representative list of necessary LCM modifications); Ex. 10, O'Connor Rebuttal at Schedule 32 (capital project summary sheets from 2003 showing need for replacement feedwater heaters, reactor feed pumps and motors, distribution infrastructure and 2012 Equipment Improvement Long Range Plan Request forms for changes to the 4 kV breaker and switchgear) (Non-Public).

management,[44] decision points,[45] contractual arrangements,[46] cost-benefit analyses,[47] resource planning needs,[48] and evolving circumstances.[49] We further supported that presentation with the independent, expert testimony of witnesses with extensive experience in the design[50] and implementation[51] of projects like ours. We believe this presents a *prima facie* case that the Program costs were prudent.[52]

In contrast, the Department, the OAG and XLI rely largely on general commentary that the Company's documentation was insufficient – without identifying what

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[42] *E.g.*, Ex. 9, O'Connor Rebuttal at Schedule 12 (providing detailed information about the Containment Accident Pressure ("CAP") issue and communications from the NRC from March 2009 through June 2010 regarding the status of the CAP issue); Ex. 3, O'Connor Direct at 30:16-42:22 and Schedule 8 (identifying and explaining cost drivers); Ex. 9, O'Connor Rebuttal at 75:16-76:8 and Schedule 27 (explaining costs associated with as-found conditions).

[43] *E.g.*, Ex. 9, O'Connor Rebuttal at Schedule 35 (contemporaneous documentation from 2007 regarding project planning and decision to proceed with the 13.8 kV system upgrade); Ex. 17, O'Connor Surrebuttal at Schedule 6 (contemporaneous document showing that the Company always considered the LCM/EPU as an integrated project) (Non-Public).

[44] *E.g.*, Ex. 3, O'Connor Direct at Schedule 14 (contemporaneous document depicting the project organizational structure in 2007). Ex. 9, O'Connor Rebuttal at 61:13-62:3 (discussing examples of project management decisions that made work during outages more efficient and reduced costs).

[45] *E.g.*, Ex. 9, O'Connor Rebuttal at Schedule 4 (presentation slides from when the Governance Council approved the Monticello relicensing strategy in July 2003) and Schedule 5 (contemporaneous documents of the information used by the Financial Council in August 2006 to recommend a unified LCM/EPU Program); Ex. 9, O'Connor Rebuttal at 69:21-70:3 (Company decision to change implementations vendors for the 2013 outage); Ex. 12, Sparby Rebuttal at 19:6-28:21.

[46] *E.g.*, Ex. 3, O'Connor Direct at 46:14-49:3 (explaining decision to contract with General Electric and scope of contractual arrangements); Ex. 9, O'Connor Rebuttal at Schedule 17 (discussing documents such the 2004 General Electric Contract provided to parties during document production).

[47] *E.g.,* Ex. 2, Alders Direct at 25:16-58:6; Ex. 8, Alders Rebuttal at 21:12-28:8.

[48] *E.g.,* Ex. 2, Alders Direct at 18:3-20:15; Ex. 8, Alders Rebuttal at 3:10-12:4.

[49] *E.g.*, Ex. 3, O'Connor Direct at 91:20-92:22 (explaining how the NRC's new "Fatigue rule" exacerbated the pre-existing shortage of experienced craft labor).

[50] *See generally* Ex. 4, Stall Direct and Ex. 13, Stall Rebuttal.

[51] *See generally* Ex. 11, Sieracki Rebuttal.

[52] *Fidelity Bank & Trust Co*, 261 N.W.2d at 590 ("[w]here a plaintiff proves a prima facie case and it is unrebutted by defendant, the plaintiff has met his burden of proof"); *Elk River Concrete Prods. Co.*, 129 N.W.2d at 314 (holding that the prima facie case had been met and the burden of production going forward switches to the defendant); *Bass*, 299 N.W. at 681 ("plaintiff made a prima facie case, one which without opposing evidence should have prevailed," and that "the burden of going on with evidence" should have shifted to the defendant upon the plaintiff's production of "all the evidence to be expected of him").

information was missing or was requested and not provided[53] – thereby requiring the utility to "prove the negative" that it was not imprudent.[54] We do not believe this is enough to overcome the substantial evidence we provided.

Nor is it enough to speculate that it is "likely" costs could have been lower if the Company had done things differently. In the first 55 pages of the Department's Brief, they say 22 times that costs would *likely* have been lower had the Company done things differently. However, in none of these instances does the Department specifically state that the Company's choices were imprudent or quantify cost increases caused by imprudence. This is particularly telling here, because Mr. Crisp (the Department's lead implementation management witness) testified that he did not address specific costs and that cost increases can happen with no imprudence.[55] Consequently, the Department's arguments do not serve to rebut a *prima facie* case.

2. The Company's Evidence Was Credible

The OAG's Initial Brief devotes considerable space to attacking the credibility of the Company's witnesses.[56] The OAG argues that (i) Mr. Sparby's compensation made him biased, (ii) Mr. O'Connor's testimony was not credible, (iii) the other witnesses were suspect, and (iv) the 2011 Cost History was a sort of "smoking gun" from which the Company has tried to hide. The OAG's overheated rhetoric relies heavily on innuendo and speculation, and too often is fundamentally wrong.

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[53] *E.g.,* Ex. 421, Jacobs Opening Statement at 3 ("Finally, I observe the Company's rebuttal testimonies are voluminous but not substantive."). Nowhere does Dr. Jacobs suggest what information was necessary but missing from the Company's case. He simply disagrees with the Company's conclusions.

[54] *See State v. Paige*, 256 N.W.2d 298, 304 (Minn. 1977) (recognizing legal impossibility of proving a negative).

[55] Tr. Vol. III (Crisp) at 17:20-22; 18:21-25 and 59:9-12.

[56] OAG Initial Br. at 10-13.

a. Mr. Sparby's Credibility

Mr. Sparby has worked for Xcel Energy and its predecessor for more than 33 years and has held positions that included overseeing Minnesota state regulatory affairs, to Chief Financial Officer of the corporation, to his current position as president of Xcel Energy's Minnesota operations.[57] Mr. Sparby has appeared before the Commission and the Office of Administrative Hearings many times over the years.

Contrary to the OAG's assertion that Mr. Sparby was too busy to pay attention,[58] Mr. Sparby was an engaged and active executive.[59] Mr. Sparby participated in key decisions as he was alternately president of the utility or CFO during virtually the whole run of the Program.[60]

The OAG argues that Mr. Sparby's compensation gives him an interest in the outcome of the case but does not otherwise suggest that Mr. Sparby's testimony is wrong or, in fact, biased.[61] Mr. Sparby's compensation does not diminish his breadth and depth of experience with the Company and with the Commission. All Company employees (and other stakeholders as well) have a stake in the outcome of this proceeding, as it presents important issues that merit serious consideration. Mr. Sparby's compensation does not change the importance of this inquiry or the importance of his perspective, given his direct involvement in executive management and oversight of the Program. The proper focus here is not the impacts on any individual (since any employee or contractor of any Party would be subject to the same criticism) but the underlying facts and policy considerations.

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[57] Ex. 12, Sparby Rebuttal at 1:8-2:23.

[58] OAG Initial Br. at 12.

[59] Ex. 12, Sparby Rebuttal at 2:19-20 ("While CFO, I was regularly involved with the financial aspects of the LCM/EPU Program."); at 9:3-8 (describes involvement in accounting); at 25:18-25 (discusses governance process); at 28:18-21 (discusses his involvement in considering whether to abandon initiative after 2011 outage).

[60] Ex. 12, Sparby Rebuttal at 3:24-4:9.

[61] OAG Initial Br. at 11.

Finally, Mr. Sparby provides a valuable perspective on the potential impact this case could have. In his current position as president of the utility and former position as CFO, he is well placed to provide a discussion of the Company's overall financial health if a punitive outcome is imposed: "I am concerned about the impact of the Department's proposal on the financial health of the utility, particularly in light of the current record. A significant disallowance without specific facts supporting imprudence or harm could send a signal to our investors that our nuclear programs do not have strong regulatory support in Minnesota."[62] An overly punitive outcome would send the wrong signals to the financial markets, which could be detrimental to all Xcel Energy stakeholders, including employees and potentially ratepayers if adverse financial consequences increase borrowing costs.

b. Mr. O'Connor's Involvement

The OAG seeks to marginalize Mr. O'Connor's involvement by asserting (i) he joined the effort late, (ii) he was not in charge during the Program, and (iii) he was uninformed.[63] This is nothing more than an attempt to deflect attention from the OAG's own witness, who relies exclusively on the Department's witnesses, acknowledges not knowing one of the main contractors he was criticizing,[64] and admits his "expertise" in construction and project management was in the controller's function in a manufacturing company more than 25 years ago.[65]

[62] Ex. 12, Sparby Rebuttal at 33:3-7.

[63] OAG Initial Br. at 12-13.

[64] Tr. Vol. IV (Lindell) 96:1-15.

[65] Tr. Vol. IV (Lindell) 97:15-18.

In contrast, Mr. O'Connor has over 30 years experience in the nuclear industry and has worked at several other nuclear plants,[66] providing him with broad experience. He joined Xcel Energy in 2007 and became the Site Vice President at Monticello.[67]

The OAG suggests joining the Company in 2007 was "well into the planning process" and put Mr. O'Connor out of the sphere of influence. The OAG is quite wrong on this point. As Mr. O'Connor explained, 2007 was a critical year in the design and planning process, which saw many important decisions made to support the success of the overall initiative.[68]

Mr. O'Connor's role as Site Vice President gave him a critical vantage point to influence design choices for the best interests of the plant:

> In 2007, we decided to replace the reactor feed pumps and motors with larger capacity equipment to meet the operational and uprate needs of Monticello. In September 2007, we convened an "Electrical Summit" to evaluate the options for accommodating the replacement reactor feed pumps and other new equipment.[69]

Furthermore, in his executive role at the Plant, and as we described on pages 103-104 of our Initial Brief, Mr. O'Connor played an important role in many of the key decisions in the Program. For example, the Site (which he oversaw) influenced design changes to improve the day to day usability of the Plant for our NRC-licensed operators. He was in an important position to ensure that internal plant resources were available to the Program.

The OAG goes on to assert that Mr. O'Connor was not the "ultimate decision maker" at the time. However, the record evidence demonstrates that Mr. O'Connor

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[66] Ex. 3, O'Connor Direct at 1:11-18 and Schedule 1.

[67] Ex. 3, O'Connor Direct at Schedule 1.

[68] Ex. 3, O'Connor Direct at 7:16-8:8.

[69] Ex. 3, O'Connor Direct at 131:3-14.

used his executive role to make and carry out key decisions. Mr. O'Connor was the one who signed the EPU license amendment application and, as Dr. Jacobs has pointed out, did so "under penalty of perjury."[70] Mr. O'Connor was personally involved in the selection and retention of Day Zimmerman as the initial installation contractor and oversaw the decision to keep Day Zimmerman on for the 2011 installations.[71] He was personally involved in the issues surrounding the 2011 outage and "was disappointed by the difficulties we encountered."[72] Mr. O'Connor describes in detail the management oversight process in selecting Bechtel as the installation contractor for the final (and most difficult) 2013 outage.[73] And there is no dispute on this record that Mr. O'Connor "worked hard at all times to provide accurate information to both the NRC and the State."[74]

c. Other Company Witnesses' Credibility

The OAG questions why we did not have former CNO Dennis Koehl or former LCM/EPU Program manager Al Williams testify.[75] The reason is that neither is employed by Xcel Energy at this time. Even more importantly, the Program was a corporate effort. We made our current employees available, including, for example, Mark Schimmel[76] who answered many of the Information Requests, and Nate Haskell,[77] the Director of Engineering. They have ample experience with the Program and had access to the documents to develop our presentation.

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[70] Ex. 9, O'Connor Rebuttal at 86:14-87:3; *see* Ex. 305, Jacobs Direct at 8:27.

[71] Ex. 3, O'Connor Direct at 76:1-5.

[72] Ex. 9, O'Connor Rebuttal at 68:25-26.

[73] Ex. 3, O'Connor Direct at 83:23-84:3.

[74] Ex. 9, O'Connor Rebuttal at 87:2-3.

[75] OAG Initial Br. at 13, 34.

[76] *See, e.g.*, Ex. 9, O'Connor Rebuttal at Schedule 9 at 2; Schedule 14 at 5; Schedule 19 at 12. Mr. Schimmel is a vice president of Xcel Energy who served as Site Vice President at Monticello after Mr. O'Connor.

[77] *See* Ex. 9, O'Connor Rebuttal at Schedule 23 at 5, 16; Schedule 28 at 7.

Further, the Parties who participated were able to obtain information from a variety of sources. For example, the Company gave the Department access to the Plant and key plant employees to interview. These employees included not only Mr. O'Connor, but also Mr. Schimmel (site Vice President at the time), Mr. Haskell (Engineering Director, who personally oversaw the design effort for the Program), and Mr. Bjorseth (the LCM/EPU Program Manager). Although these interviews were conducted on an informal basis (meaning they were not transcribed or treated like formal depositions), they provided the Department an additional opportunity to gather information and ask questions they considered important.

Lastly, the OAG generally criticizes the remaining four Company witnesses (Alders, Weatherby, Sieracki and Stall). The OAG maintains that (i) Mr. Alders is not credible because he relied on the modeling work of subject matter experts in the normal course of his duties, (ii) Mr. Weatherby's accounting testimony and data is irrelevant, and (iii) the Company's two external experts are being paid and therefore should not be believed.[78] The OAG's criticisms of these witnesses is unpersuasive.

Mr. Alders has nearly 40 years with the Company[79] and was the case manager on the Certificate of Need and Resource Plan proceedings relevant to this case.[80] Mr. Alders' testimony provides background for the resource planning considerations that influenced our approach to the initiative. There is no one better to provide that information since Mr. Alders had first-hand knowledge of both the 2005 and 2008 Certificates of Need and had first-hand knowledge.

The OAG's observation that Mr. Alders did not personally conduct the Company's modeling work does not discredit his testimony in any way. It is commonplace in the

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[78] OAG Initial Br. at 13.

[79] Ex. 2, Alders Direct at 1:17.

[80] Tr. Vol. I (Sparby) 36:8-10.

industry to rely upon subject matter experts in preparing technical data, especially financial modeling. Additionally, Mr. Alders has decades of experience in resource planning.[81]

> Judge, my background is the result of almost 40 years of experience with the company in certificate of need matters for power plants and transmission lines. I have been directly involved with our modelers and resource planners working on resource planning matters for the last 22, 23 years.
>
> My responsibility is to work with them and prepare our certificates of need, work with them and prepare our resource plans….[82]

Likewise, the OAG misses the point of Mr. Weatherby's testimony; he provided the accounting records to support our presentation and facilitate the Department's audit. As Ms. Campbell acknowledged, the total costs provided by Mr. Weatherby represent the actual cost of the initiative.[83] His testimony served that purpose.

Finally, the OAG observes that our two retained experts (Mr. Stall and Mr. Sieracki) were paid to prepare their independent assessments of our performance. We agree. However, the fact that an external expert is paid does not change the substance of the opinions given. And we note that the OAG relies extensively on the Department's paid consultants, Mr. Crisp and Dr. Jacobs. We believe it is better to address all of the experts on the merits of the analysis and opinions.

In particular, Mr. Stall has targeted and on-point experience, having overseen the same project at FPL where "the cost increases at the St. Lucie and Turkey Point were significantly more than the cost increases at Monticello, but they had the same [sic]

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[81] Ex. 413, Alders Opening Statement at 3.

[82] Tr. Vol. II (Alders) 19:6-16.

[83] Tr. Vol. IV (Campbell) 134:10-18.

similar challenges."[84] FPL received 100 percent rate recovery for their increased costs.[85] Far from being impeached, Mr. Stall's targeted experience with "same/similar challenges" establishes him as a more persuasive expert than Dr. Jacobs, whose recommended disallowances have been rejected in the past.[86]

Mr. Sieracki provided helpful review of the principles of prudent project management and the issues that often arise in connection with major, multi-year, construction projects. Unlike Mr. Crisp, upon whom the OAG places great reliance, Mr. Sieracki's testimony provides detailed analysis and a fact-based discussion of the issues the Company faced. And unlike Mr. Crisp's speculation that costs were "likely" higher although he did not address whether the Company was prudent or imprudent, Mr. Sieracki took a critical view of the Company's performance. He acknowledged our performance was not perfect[87] and that the Company benefited from "lessons learned" that identified areas for improvement.[88] Program management could have been planned and executed better, but was "hardly imprudent."[89] Based on 40 years of experience[90] with major construction projects and his detailed review of the same types of documents[91] provided to the Department in discovery, Mr. Sieracki found the Company's performance to fall within the zone of reasonableness.[92]

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[84] Tr. Vol. III (Jacobs) 105:2-5.

[85] Tr. Vol. III (Jacobs) 105:6-19. And Dr. Jacobs' request for a $200 million disallowance in Florida was rejected as unsupported. Tr. Vol. III (Jacobs) 110:12-19, 113:8-23; Ex. 425, *Final Order Approving Nuclear Cost Recovery Amounts for Fla. Power & Light Co. and Duke Energy Fla., Inc.*, Fla. Pub. Serv. Comm'n No. 130009-EI, at 36 (Oct. 18, 2013).

[86] Tr. Vol. III (Jacobs) 110:12-19, 113:8-23; Ex. 425, *Final Order Approving Nuclear Cost Recovery Amounts for Fla. Power & Light Co. and Duke Energy Fla., Inc.*, Fla. Pub. Serv. Comm'n No. 130009-EI, at 36 (Oct. 18, 2013).

[87] For example, he testified that "[t]here is a normal level of disruptive events that occur on most projects of this magnitude and certainly areas offering the potential for improvement." Ex. 11, Sieracki Rebuttal at 30:2-4.

[88] Ex. 11, Sieracki Rebuttal at 5:15-20.

[89] Ex. 11, Sieracki Rebuttal at 31:19-20.

[90] Ex. 11, Sieracki Rebuttal at 1:15-3:20.

[91] *Compare* Ex. 11, Sieracki Rebuttal at 4:23-5:2, *with* Tr. Vol. III (Jacobs) 100:17-103:3.

[92] Ex. 11, Sieracki Rebuttal at 10:5-13.

In sum, we believe general attacks on witness credibility are unfounded.

III. REPLY TO SPECIFIC CRITICISMS

In this section of our Reply Brief, we address the key criticisms raised by the Department, OAG, and XLI in their Initial Briefs.

- First, we address the Department's and OAG's arguments about our initial cost estimates for the Program and decision to proceed.

- Second, we address all Parties' allegations, relying primarily on Mr. Crisp, about our initial planning and design, including (i) the Program implementation timeline; (ii) parallel path/multi-tracking; (iii) NRC communications; and (iv) Program design.

- Third, we address all Parties' allegations, relying again on Mr. Crisp, regarding our management of the Program: (i) our use of a dedicated project team; (ii) various contractor management claims, (iii) general project oversight, and (iv) our contractor selection and oversight. We also reiterate in this section that we built the right Program, as well as highlight several of the unacknowledged complexities we faced.

- Fourth, we address the Department's contention that an LCM/EPU split is appropriate to determine cost-effectiveness of the Program after the fact, and specifically Dr. Jacobs' proposed LCM/EPU split.

- Fifth, we respond to the Department's and OAG's other criticisms that do not pertain to prudence per se, such as questions about our accounting for the Program, our regulatory communications regarding the Program, and other performance questions that do not relate to the LCM/EPU Program.

- Sixth, we address the Parties' proposed remedies and the need for any remedy to be associated with a finding of imprudence that actually caused harm.

- Finally, we summarize the conclusions to be drawn upon reviewing all the Parties' criticisms and the overall body of evidence on the reasonableness of our decisions and actions.

A. Decisions to Pursue Program

The Department and OAG raise two primary concerns regarding the Company's initial cost estimates for the Program: (1) whether the initial cost estimate was reasonable, and (2) whether the Company should have provided more or different information in the ISFSI and EPU Certificate of Need proceedings. We respectfully submit that the first issue pertains to the prudence of our Program decisions and actions, while the second goes more to the substance of Certificate of Need filings generally and is not determinative of findings of prudence or imprudence in this proceeding. Nevertheless, we address each concern in turn. We also address the Department's mistaken conclusion that our $320-346 million cost estimate represents escalation of Program costs to 2014 (rather than 2008) dollars.

1. Reasonableness of Initial Cost Estimate

The Department's Initial Brief first raises concerns about the initial cost estimate for the Program and suggests that application of the Department's 2014 cost-effectiveness analysis to the 2008 Certificate of Need may have caused a different outcome in the Certificate of Need proceedings.[93] In particular, the Department notes:

> The Department's analysis, discussed in this Initial Brief, indicates that Xcel's cost representations, particularly in the 2008 Certificate of need,

[93] Department Initial Br. at 8.

> were inadequate, given what Xcel knew or should have known in 2008. Had Xcel represented its costs reasonably in the EPU [Certificate of Need] proceeding, the Department would not have supported granting a certificate of need for the EPU since other alternatives would have been more cost effective."[94]

The Company reads this paragraph to suggest that the Department would not have supported the decision to proceed with the Program in 2008, based on what it knows today. In fact, the Department's conclusion depends on two factors that only became known years after the fact: (1) the final cost of the Program; and (2) Dr. Jacobs' 2014 LCM/EPU split attributing 85.7 percent of final Program costs to the EPU.

The record is clear, however, that neither of these facts were known or reasonably knowable in 2008, when the Commission considered the EPU Certificate of Need. What we knew at the time was that there was high forecast demand for baseload power additions and high natural gas prices. Using final Program costs or Dr. Jacobs' split requires relying on hindsight, which is contrary to the prudent investment standard:

> In an industry that combines long lead times for plant construction with wide fluctuations in supply and demand, constant changes in the regulatory environment, and unpredictability in the availability and price of alternative sources of fuel, some projects that seem prudent at the time when costs are incurred may appear, some years later, in hindsight, to have been unnecessary or inadvisable. [95]

To end any doubt, the record evidence demonstrates that our work was cost-effective in 2008 based on what was known or reasonably could have been known at that time. The Company provided substantial evidence showing that we explored multiple options to meet customer needs through several resource plans (including resource plans from 2002, 2004, and 2007), the 2005 ISFSI Certificate of Need, and the 2008

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[94] Department Initial Br. at 8.

[95] *Violet v. F.E.R.C.*, 800 F.2d at 282; *see Re New England Power Co.*, 31 FERC at 61,084.

EPU Certificate of Need. We described these alternatives on pages 40-43 of our Initial Brief. Further, our initial $320-346 million estimate (2008) in the 2008 Certificate of Need proceeding was based on (i) the initial feedback from General Electric; (ii) benchmarking comparables we had studied; (iii) internal assessments of the Plant; and (iv) additional funds for the steam dryer and escalation to 2008 dollars.[96] None of that information suggested – *at the time the Program cost estimate was developed* – that the Company had not adequately scoped the EPU. The scoping claims in this proceeding have only arisen years after the fact, which is classic hindsight and second-guessing.[97]

The Department's arguments regarding the initial Program cost estimate are based largely on Mr. Crisp's discussion of the level of contingency he believed could have been used for Program cost estimates. The Department now relies on Mr. Crisp's post-Certificate of Need (November 29, 2011) "Cost Estimate Classification System" document[98] to argue that the Company should have factored a 100 percent contingency into its 2008 Certificate of Need cost estimate. The Company discusses this issue on pages 91-94 of our Initial Brief, and maintains that the Department's argument is unsupported. As explained in our Initial Brief, inclusion of a contingency does not affect cost or speak to whether costs were reasonably incurred.[99]

Moreover, the document on which Mr. Crisp relies does not discuss a 100 percent contingency, but rather that a *minus 50 to plus 100* percent "estimated accuracy range" (not simply a plus-100 to 150 percent contingency) is appropriate for an early-stage

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

[97] *In re GPU, Inc.*, 96 Pa. P.U.C. at 91-92; *In re Long Island Lighting Co.*, 24 N.Y.P.S.C. at *6; *Pennsylvania Pub. Util. Comm'n*, 71 Pa. P.U.C. at 42 (noting that the commission "must assess the reasonableness of a utility's decision-making based on the state of information available when decisions had to be made and without reliance on hindsight.").

[98] Ex. 303, Crisp Surrebuttal at Attachment MWC-S-1.

[99] Xcel Energy Initial Br. at 91; Ex. 303, Crisp Surrebuttal at 21:8-9.

project estimate *after* calculation of the contingency.[100] This document therefore illustrates the common understanding regarding early phase estimates, and does not speak to whether the Company's contingency[101] was too high or too low.

In fact, the Company has never provided such a wide range of potential outcomes and neither did other utilities embarking on uprates. Grand Gulf, for example, provided a cost estimate ranging from $420 to $470 million based on preliminary conceptual design work.[102] Florida Power & Light provided even more targeted initial estimates of approximately $750 million and approximately $651 million for the Turkey Point and St. Lucie uprates, respectively.[103] A wide range of potential outcomes does not mean that a utility would not budget an appropriate level of contingency and identify what it believes to be the most reasonable anticipated final cost.

Finally, the Department's conclusion that the EPU Certificate of Need was not cost-effective in 2008 depends entirely upon Dr. Jacobs' after-the-fact 14.3/85.7 percent LCM/EPU split in this proceeding. While the Department argues Dr. Jacobs' split is correct based on final Program costs (an argument with which the Company disagrees, as discussed later), no witness has suggested that in 2008 the Company should have anticipated a hired consultant's after-the-fact split. Indeed, while the Department disagrees with application of the Certificate of Need 58.4/41.6 percent

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[100] Ex. 303, Crisp Surrebuttal at Attachment MWC-S-1 at 2-3.

[101] Ex. 9, O'Connor Rebuttal at Schedule 13 at 2. The initial contingency in the $320-346 million cost estimate was "$15.431 million plus $7 million in 2006 dollars for two different contingencies."

[102] *In re Joint Petition of Sys. Energy Resources Inc., and S. Miss. Elec. Power Ass'n for a Certificate of Pub. Convenience and Necessity to Construct, Own, Operate, and Maintain an Extended Power Uprate Modification and Related Facilities at the Grand Gulf Nuclear Station in Claiborne Cnty., Miss.*, Miss. Pub. Serv. Comm'n No. 2009-UA-260, JOINT PETITION FOR FACILITIES CERTIFICATE AND MOTION FOR WAIVER at 5 (May 22, 2009). Grand Gulf also noted that their estimates did not include any costs associated with constraints that may be identified during the detailed analysis phase of the project. *In re Joint Petition of Sys. Energy Resources Inc., and S. Miss. Elec. Power Ass'n for a Certificate of Pub. Convenience and Necessity to Construct, Own, Operate, and Maintain an Extended Power Uprate Modification and Related Facilities at the Grand Gulf Nuclear Station in Claiborne Cnty., Miss.*, Miss. Pub. Serv. Comm'n No. 2009-UA-260, at DIRECT TESTIMONY OF C. JEFFREY RICHARDSON at 27:6-11 (May 22, 2009).

[103] *In re Fla. Power & Light Co.'s Petition to Determine Need for Expansion of Elec. Power Plants*, Fla. Pub. Serv. Comm'n No. 070602-EI, DIRECT TESTIMONY & EXHIBITS OF STEPHEN T. HALE at 13:7-10 (Sept. 17, 2007).

LCM/EPU split to final Program costs, no witness has contested that this split was based on the facts and information known at the time of the Certificate of Need.[104]

Although we believe our cost estimates were reasonable based on the information we knew in 2008, the Company acknowledges that there was a potential to use somewhat higher cost estimates. We have acknowledged that Monticello needed more LCM work than we realized during the ISFSI and the EPU Certificate of Need proceedings. We have further acknowledged that we could have reasonably identified an initial Program cost estimate of up to about $420 million ($2008$). But even if the Company had applied a 100 percent contingency adder to the Program cost estimate for a total initial estimate close to final costs, this approach would not have changed the portion of the Program the Company estimated would be attributed to LCM or the EPU. Even the Department acknowledges the Program is cost-effective if less than 73 percent of Program costs are attributed to the EPU. Thus, application of the 2008 Certificate of Need LCM/EPU split to either original or final costs underscores that the Program would have been cost-effective under both circumstances. As such, it is incorrect to suggest the EPU might not have been approved in 2008.

The Department's use of hindsight with respect to both the overall cost and the split became so apparent that Department witness Mr. Shaw confirmed that prudence is not synonymous with cost-effectiveness. In response to our criticisms of the Department's use of a proxy remedy, Mr. Shaw stated that "Xcel confuses a general prudence standard with the Department's application of our proposed remedy in this case"[105] and clarified that "as a general matter, continued cost-effectiveness does not

[104] Ex. 307, Jacobs Surrebuttal at 16:3-7.

[105] Ex. 311, Shaw Surrebuttal at 3:20-21.

equate with prudency."[106] However, a traditional prudence analysis is how the Monticello LCM/EPU Program must be assessed.

In closing, the Company respectfully asks the ALJ and Commission to reject the Department's claim that the Company's initial cost estimate was not reasonable based on final, actual Program costs, coupled with the Department's 2014 14.3/85.7 percent LCM/EPU split. The evidence in this record demonstrates the actual estimate was reasonable based on the information reasonably available to the Company at the time, and the Company could not have known the ultimate cost or Dr. Jacobs' LCM/EPU split in 2008.

2. Level of Detail in Certificate of Need Filings

The Department also suggests that the level of discussion of LCM work in the two Certificate of Need proceedings was insufficient. We do not think this criticism supports any adverse finding, for several reasons.

First, the ISFSI Certificate of Need was for authority to install dry casks rather than for an uprate or for specific life-extension projects.[107] We provided detailed cost information relating to the dry casks that were the subject matter of that proceeding. This work was authorized and has not been challenged in this proceeding.[108]

Second, we included a "representative" list of the types of LCM work we expected would need to be undertaken if Monticello's license was renewed.[109] We were clear

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[106] Ex. 311, Shaw Surrebuttal at 7:2-3.

[107] *See* Ex. 2, Alders Direct at 17 n.4 (citing *Application to the Minn. Pub. Util. Comm'n for a Certificate of Need – Monticello Spent Nuclear Fuel Storage*, No. E002/CN-05-123 ORDER GRANTING CERTIFICATE OF NEED FOR INDEPENDENT SPENT FUEL STORAGE INSTALLATION at 16 (Oct. 23, 2006)).

[108] *See* Ex. 9, O'Connor Rebuttal at Schedule 4 at 19.

[109] Ex. 9, O'Connor Rebuttal at 12:17-13:9 and Schedule 6 at 13-14.

that this list was not based on an exhaustive study, but was representative based on good faith estimates and prior experience at the time.[110]

Third, consistent with Minnesota law, the EPU Certificate of Need application focused on the uprate because that was what necessitated the permit. So while LCM costs were included in modeling, there was no focus on the nature or extent of necessary LCM work.

Similarly, the OAG takes issue with our discussion in the EPU Certificate of Need regarding the scope of work underlying our initial estimate.[111] The OAG argues:

> When Xcel filed the CON for the Monticello EPU, the Company outlined all of the major modifications it believed would be necessary to finish the project. In that filing, Xcel told the Commission that it had "comprehensively evaluated the effects of the extended power uprate at Monticello," and that only "smaller scope modifications [would] be identified during the detailed engineering phase of the project." Unfortunately for the Company, and for ratepayers, this has not been the case.[112]

The OAG's argument relies on a segment of a larger discussion such that the OAG's conclusion is incorrect for three reasons.

First, the Company's Petition made clear from the outset that the scope of work to be completed for the overall Program was significant with respect to the balance of plant systems:[113]

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110 Ex. 2, Alders Direct at 16:26-17:2.

111 OAG Initial Br. at 26-27.

112 OAG Initial Br. at 26 (citing *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 3-13 and 3-16 (Feb. 14, 2008)).

113 *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 3-15 (Feb. 14, 2008).

> The balance–of-plant systems that convert the steam produced in the reactor to electricity however will need significant modifications.

The Company then identified "significant" modifications with some detail in paragraphs A.-J. on pages 3-16 to 3-19 of the Petition. That is the very work that drove much of the cost increase and included, for instance, the modification with the largest cost increase – the 13.8 kV electrical distribution system.

Second, the OAG's quote about "smaller modifications" is incomplete, leaving out the key context:[114]

> The major modifications and a short description of the work to be completed on each during the two refueling outages are listed below. Additional smaller scope modifications will be identified during the detailed engineering phase of the project.

The "*additional* smaller scope modifications" were separate from the larger modifications that drove much of the cost, and which were "listed below" in paragraphs A.-J. on pages 3-16 to 3-19 of the Petition. In short, the Company was informing the Commission there was "smaller" work *in addition to* the larger items mentioned in paragraphs A.-J.

Third, the Petition statement that "NMC, in conjunction with the designer of Monticello, GE, has comprehensively evaluated the effects of the extended power uprate at the Monticello"[115] is referencing the comprehensive evaluation that was performed to ensure the nuclear reactor could handle the power uprate. The work on the Program encompassed the balance-of-plant systems, not the nuclear reactor. The comprehensive evaluation referenced in the Petition was one that ensured that

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[114] *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 3-16 (Feb. 14, 2008).

[115] *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 3-13 (Feb. 14, 2008).

"sufficient safety and design margins exist such that the rated core thermal power can be increased from 1775 to 2004 megawatts thermal ("MWt") without any adverse impact on the health and safety of the public and without any significant impact on the environment."[116] It was not a statement representing that design on Program modifications for balance-of-plant systems was complete or near complete. Overall, the OAG has created an argument based on selective and misleading citations. The arguments that our cost estimates were unsupported at the Certificate of Need stage do not reflect the facts available at that time.

3. Adjusted Certificate of Need Estimate

The Department also is under the mistaken belief that the $346 million initial estimate is a number that was escalated to present day dollars, relying on our answer to Department Information Request No. 94.[117] The Department has misread our answer to that question, which merely conveyed that the initial pre-Certificate of Need estimate of $273 million was increased by adding the Steam Dryer and escalated to 2008 dollars to develop the $320-346 million range that was used in the 2008 EPU Certificate of Need Application.[118] Indeed, we had no reason to escalate to 2014 dollars for purposes of a 2008 Certificate of Need filing, particularly for a project we expected at the time would be placed in service following our 2011 outage. This issue was covered in our Initial Brief at page 86.

The record establishes that the initial authorization for the Program was for $273 million ($2006$) to complete LCM/EPU modifications that the Company identified, obtain a Certificate of Need from the Commission, and prepare the NRC license

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[116] *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 3-13 and 3-14 (Feb. 14, 2008).

[117] Department Initial Brief at 88-89; Ex. 313, Campbell Direct Attachments at NAC-5 at 3.

[118] Ex. 314, Campbell Direct Attachments at NAC-5 at 3.

amendment request with implementation of the Program.[119] This estimate did not include the cost of installation of components and modifications that were to be provided by a third Party and did not include the Steam Dryer replacement identified later.[120]

Adding the steam dryer and escalation to 2008 made the estimate $320 million, which is what was primarily used for modeling. The Company then also used a sensitivity of $346 million as added contingency in its modeling.[121] The $346 million included in the 2008 Certificate of Need was in 2008 dollars.[122] Without AFUDC, $346 million in 2008 dollars equates to $397.5 million in 2014 dollars.[123] With AFUDC added, the initial estimate in 2014 dollars is $453 million, which is an apples-to-apples comparison with the $748 million used by the Department.[124]

4. Decisions to Continue

The Department also questions the Company's decision to pursue the Program to completion because Mr. Crisp claims that pursuing the initiative became unnecessary because the economy "around the country has taken pretty much a nose dive since the 2008 economic downturn."[125] This testimony suggests that we did not need to continue with our approach "once you got into the actual 2010-2011 time frame."[126]

There are several problems with this argument. First, it contradicts portions of the Department's Initial Brief where the Department acknowledges that "the Company

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

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

[121] Ex. 3, O'Connor Direct at 29:14-30:3 and 30:2 at Table 5.

[122] Ex. 15, Alders Surrebuttal at 15:9-11.

[123] Ex. 15, Alders Surrebuttal at 15:14-15.

[124] Ex. 15, Alders Surrebuttal at 15:12-15.

[125] Department Initial Br. at 33 (quoting Tr. Vol. III (Crisp) at 70:15-24)).

[126] Department Initial Br. at 33 (quoting Tr. Vol. III (Crisp) at 70:15-24)).

could not have anticipated the significant changes due to the Great Recession and hydraulic fracturing."[127] Second, it is not based on any specific assessment of need in 2010 or 2011, but rather a general opinion about economic changes. Third, as Mr. Alders describes, the Company's demand forecast did not "nose dive" right after the 2008 market crash; it was not until 2010 that the economy and our forecasting efforts were showing a new economic 'normal.'[128] Fourth, natural gas prices (another major driver of this initiative) continued to be high until the advent of hydraulic fracturing, which did not have a material impact on natural gas prices until 2011.[129] These specific, unrebutted facts result in a conclusion contrary to Mr. Crisp's high-level assertion.

Finally, we had no real opportunity to change our approach after 2009 because by that time we were fully committed to completing the work. As Mr. Alders summarized:

> By the end of the 2009 outage, we had already spent about $200 million on engineering, licensing and construction, including about $75 million that had been spent in the 2009 outage itself. At that point the Program was roughly on track and had exceeded our forecasts by a relatively small amount. Seeking to withdraw the certificate of need at that time would have been inconsistent with our experience to that point and would have been inconsistent with our desire to upgrade the plant and add incremental capacity. We had no evidence at the time that would contradict the Commissions certificate of need Order.[130]

More specifically, in May 2010 the Company conducted an internal analysis to determine whether the costs associated with the EPU remained cost effective and

[127] Department Initial Br. at 70.

[128] Ex. 2, Alders Direct at 51 n.18.

[129] Ex. 2, Alders Direct at 51 n.18.

[130] Ex. 2, Alders Direct at 60:11-18.

found that adding an additional $50 million to the EPU side of the equation was still cost effective.[131] These conclusions did not change prior to the 2011 outage:

> Prior to the 2011 implementation outage, we had already expended $280 million in furtherance of the Program. Once again, at this point we had no basis to think that we should change course. Further, stopping at that point would have resulted in significant stranded costs. By the end of the 2011 implementation outage, when it became apparent that final costs were going to substantially exceed the original estimates, we had spent $430 million.[132]

We conducted another internal analysis in May 2011 as the 2011 outage came to a conclusion, using "the original model used to evaluate the EPU Program in 2008. At the time we had identified an additional $79 million in capital above our original estimate. The analysis indicated that even if the entire $79 million was attributed to the EPU Program, it would have still been prudent to pursue the Program."[133] In light of the sunk costs at that time, coupled with our internal modeling and the Plant's need for us to complete the upgrades (e.g., feedwater heaters, additional distribution capacity, new pumps and motors) to support 20 years of operation regardless of whether we continued with an uprate. Our decision to stay the course was reasonable.

The Company's contrasting experience with Prairie Island is instructive. The Company began the uprate at Prairie Island to coincide with the timing of that plant's operating licenses, similar to our approach at Monticello. But that meant we started at Prairie Island several years later; at that time, we discovered that uprates were becoming more complex, time-consuming and expensive.[134] As Mr. Alders described:

[131] Ex. 2, Alders Direct at 51:5-10.

[132] Ex. 2, Alders Direct at 60:20-25.

[133] Ex. 2, Alders Direct at 51:17-21.

[134] Ex. 2, Alders Direct at 59:6-14.

> In the Prairie Island proceedings, construction had not yet begun and the Company was ultimately seeking a decision from the Commission whether we should go forward or abandon the project. To provide the Commission with the information needed to make such a decision, we included a significant amount of information beyond technical compliance with the rules.
>
> By contrast, in the Monticello EPU Certificate of Need Docket, we were at a very different stage in development and we were not seeking a Commission decision whether or not to change course. Unlike with Prairie Island, we had already completed a significant amount of construction at Monticello.[135]

Since we had not yet begun construction, we were in a position to reasonably consider abandoning the effort and ultimately did so at Prairie Island.[136] As explained in the preceding paragraphs, a similar opportunity did not exist at Monticello.

B. Initial Planning and Design Criticisms

The OAG's and Department's Initial Briefs question the Company's manner of initiating Program planning and implementation during the 2009 and 2011 outages. In particular, both Parties rely on Mr. Crisp to question whether the Company (i) should have delayed implementation to the 2011 and 2013 outages, thereby allowing more time for upfront planning and design;[137] (ii) reasonably undertook a parallel path approach; (iii) should have provided more or different communications to the NRC; and (iv) should have undertaken a more traditional design, bid, build approach with more upfront design at the outset.[138] We will address the Parties' specific criticisms in their Initial Briefs in turn.

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135 Ex. 8, Alders Rebuttal at 17:16-25.

136 Ex. 2, Alders Direct at 59:16-19.

137 *See* Department Initial Br. at 33; OAG Initial Br. at 19-20.

138 *See* Department Initial Br. at 32; OAG Initial Br. at 22-23.

1. Timeframe for the Work

We first address the Department's and OAG's overlapping arguments contesting the Company's 2009 and 2011 implementation timeline.[139] The Department and the OAG suggest this decision "caused delays and budget increases that could have been avoided,"[140] and was therefore unreasonable.[141] In stating these conclusions, the Department and OAG rely on the testimony of Mr. Crisp, who reached the conclusion that the 2011/2013 schedule would have been preferable (not that the 2009/2011 schedule was imprudent) without addressing the Company's then-imminent baseload or Plant equipment needs. Mr. Crisp also did not address whether delays or cost increases the Company experienced could have been avoided by choosing the later schedule, and did not address whether a delay would in fact have been more costly due to the overall increase of construction costs over time. In fact, Dr. Jacobs testified that costs would have <u>increased</u> if performed later in time.[142] Perhaps most important is the Company's evidence explaining why our 2009/2011 implementation decision was prudent at the time it was made.

a. The Original Decision

In our Initial Brief at pages 24-28, we explained that the initial timeline selected for the Program was based on the evidence and factual history that required us to proceed thoughtfully as well as expeditiously to retain Monticello's initial capacity and add additional capacity to "keep the lights on." This history included both our

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[139] OAG Initial Br. at 19-21; Department Initial Br. at 31-35.

[140] Department Initial Br. at 33 (quoting Ex. 300, Crisp Direct at 28:14-15).

[141] OAG Initial Br. at 21; Department Initial Br. at 34. The OAG's Brief states that this decision was imprudent, although relying on Department witness Mr. Crisp, who was not testifying as to prudence. The Department finds the decision was unreasonable.

[142] Tr. Vol. IV (Jacobs) at 15:8-12 (emphasis added).

forecasted demand needs over a short planning horizon (2015)[143] and Minnesota's law precluding a life extension for Monticello before 2003[144] – meaning that once the law changed and forecasted growth continued to grow, we had a lot of work to do in a relatively narrow window of time just to keep the plant running.[145]

In light of this background, Mr. O'Connor discusses in testimony and via schedules that the Nuclear business unit carefully reviewed whether it was feasible to complete the work in the 2009 and 2011 timeframe and, based on the facts available at the time, believed it was reasonable to do so.[146] The record includes evidence that the Company further considered whether that initial decision was in fact the best choice versus delaying implementation until 2011/2013.[147]

Specifically, in 2006 the Scoping Study developed by General Electric identified two potential schedule scenarios for completing the Monticello LCM/EPU project: either complete the work during the 2009 and 2011 refueling outages, or wait and complete the work during the 2011 and 2013 refueling outages.[148] Based on the analysis of the overall Nuclear business unit and the specific work believed necessary in 2008, the Project team determined that the work could be accomplished in two consecutive refueling outages in 2009 and 2011,[149] and that completing the work during the 2009 and 2011 outages was preferable for a number of interrelated reasons.

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143 *In the Matter of N. States Power Co. d/b/a Xcel Energy's Application for Approval of its 2005-2019 Res. Plan*, No. E002/RP-04-1752, INITIAL FILING at 1-1 (Nov. 1, 2004). Of course, at this time we were only considering extending the life of Monticello; the concept of expanding the capacity of Monticello came later in the 2004 resource plan docket.

144 2003 Minn. Laws 1st Spec. Sess. ch. 11, art. 1, § 2.

145 Tr. Vol. I (Sparby) at 30:17-21 (discussing that Company had enough time but not a "generous" amount of time to complete its work).

146 Ex. 9, O'Connor Rebuttal at Schedule 24 at 13; s*ee generally*, Ex. 3, O'Connor Direct at 49:7-13, 58:10-59:12; Ex. 9, O'Connor Rebuttal at 49:15-51:2 and Schedule 20.

147 Ex. 9, O'Connor Rebuttal at Schedule 20.

148 Ex. 3, O'Connor Direct at 49:7-11.

149 Ex. 9, O'Connor Rebuttal at Schedule 24 at 13.

First, this conclusion was supported by past experience in the industry[150] and was consistent with the scope of work initially identified with the assistance of General Electric.[151] Second, pursuing the 2009/2011 installation schedule was preferable to the 2011/2013 schedule because it allowed the Company to address life-cycle investments sooner rather than later. Please recall that the Company had not made significant capital investments at Monticello throughout the 1990s.

Second, the Company had determined that the uprate was the most cost-effective alternative to meet the forecasted demand.[152] The Company's demand forecast at the time showed a significant amount of need for additional baseload generating capacity to meet near-term and mid-term needs.[153] Given the long lead times for developing new baseload resources and the high, volatile price of natural gas at the time, pursuing the uprate quickly was the best alternative for meeting our demand forecast.[154]

Third, the Company determined it would be in our customers' best interest to pursue the 2009/2011 schedule.[155] As Mr. O'Connor explained:

> We sought to move quickly to capture the customer benefits of increased output over the license renewal period. It was in our customers' best interest to get the fuel savings from the upgrades for as long as possible and to spread the costs of significant construction over as long a period as possible.[156]

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150 Ex. 9, O'Connor Rebuttal at 37:25-39:25 and 38:5 at Table 3.

151 Ex. 9, O'Connor Rebuttal at Schedule 24 at 13.

152 Ex. 3, O'Connor Direct at 58:20-22.

153 Ex. 2, Alders Direct at 18:17-21.

154 Ex. 2, Alders Direct at 20:10-15.

155 Ex. 3, O'Connor Direct at 58:22-27.

156 Ex. 3, O'Connor Direct at 58:22-27.

Given what the Company knew about needed capital improvements, demand forecast, and customers benefits, the Company's decision to proceed with the earlier installation schedule was reasonable and prudent.

b. The Alternate Option

The Company recognizes that the 2011/2013 schedule could also be viewed as a reasonable alternative.[157] Indeed, within the Company there were differing opinions as to the best option. As Mr. Crisp points out, the 2011 Cost History document reflects that the Monticello site staff recommended the 2011/2013 schedule.[158]

While we appreciate reasonable minds can differ, we do not believe an action is imprudent simply because one individual has a different opinion. Indeed, the final design came from the Project team and was vetted by the Company:

> The Nuclear business unit conducted an analysis of the proposed work and the projected benefits. Based on that analysis, the Project team reasonably believed that the work could be accomplished in two consecutive refueling outages in 2009 and 2011. This conclusion was supported by past experience in the industry and was consistent with the scope of the work initially identified in the initial NPA. . . . The Project team worked with resource planning and regulatory and recommended this schedule to the Financial Council and the Board.[159]

In addition, in hindsight the option to use a 2011/2013 schedule would not have decreased costs and would have delayed the Program. The work done during the 2009 outage, which went relatively well, would have been delayed until 2011.[160] The work that was originally planned for the 2011 outage but then split between the 2011

[157] Ex. 9, O'Connor Direct at Schedule 20 at 3.

[158] Ex. 9, O'Connor Direct at 49:15-18.

[159] Ex. 9, O'Connor Rebuttal at Schedule 24 at 13. Parties erroneously point to the Company's Board of Directors despite multiple efforts to correct an inaccuracy in the 2011 Cost History memo. Our internal Finance Council approved of the 2009 and 2011 schedule prior to the Board approving the Program.

[160] Ex. 9, O'Connor Rebuttal at Schedule 20 at 2.

and 2013 outages would likely have still been too much for a single outage even with more time for planning, which would have pushed back the final work on the Program to 2015.[161] As acknowledged by Dr. Jacobs, delay would have increased costs. Also a later implementation schedule may have exacerbated the difficulties that all uprates have experienced post-Fukushima. In all, a 2011/2013/2015 implementation schedule would not have yielded any different cost.

2. Parallel/Multi-Tracking

The Department also criticizes the Company's parallel path approach, which they call "fast-tracking," as unreasonable and overly aggressive.[162] Likewise relying on Mr. Crisp, the OAG further contends that this approach led to unspoken cost increases because the largest cost increases on four Program modifications were attributable to alleged poor initial scoping.[163] These criticisms are incorrect, as discussed on pages 29-38, 59-61, and 82-95 of our Initial Brief.

In the environment in which the scheduling and multi-tracking decision was made, the Company again faced the prospect of much higher natural gas prices than today and pre-great recession load growth and capacity needs.[164] To meet this need, the multi-tracking approach was intended to complete the Program faster than an approach where all design was completed up front.[165] Based on this data, the scope of work, and the customer harm if the Company chose an alternate path, the Project

[161] Ex. 9, O'Connor Rebuttal at Schedule 20 at 2.

[162] Department Initial Br. at 31-34; OAG Initial Br. at 19-21, 35.

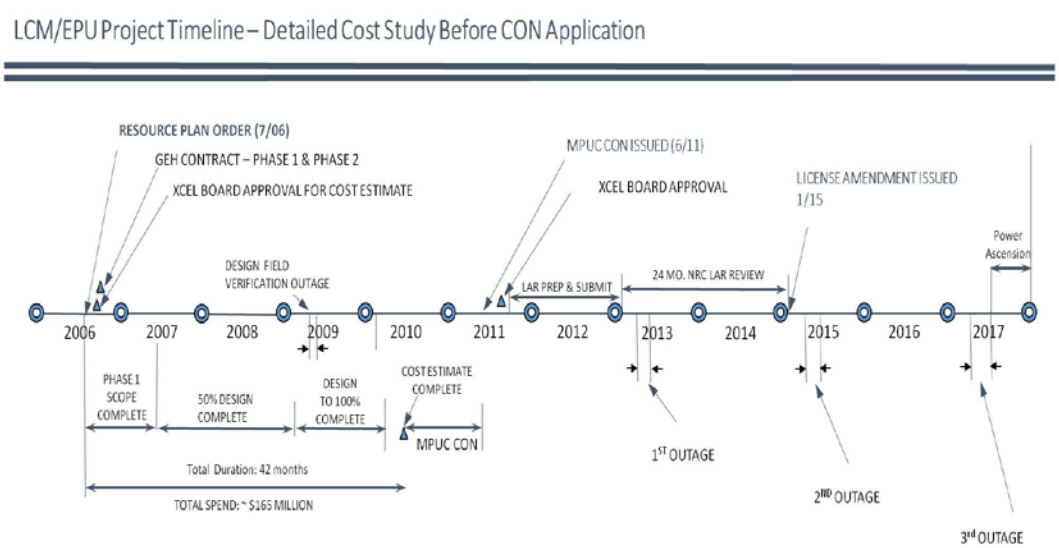
[163] OAG Initial Br. at 27-28.

[164] Ex. 8, Alders Rebuttal at 6:6-12; Ex. 11, Sieracki Rebuttal at 12:4-15:9.

[165] Tr. Vol. III (Crisp) at 30:3-8.

team believed moving forward with parallel implementation was the most appropriate decision.[166]

The Company also considered the likely outcome if it undertook additional early scoping and did not multi-track the Program. The Company provided the following timeline illustrating the impacts of choosing that alternative approach – which ultimately would have meant that the Program would not be completed until 2017:[167]



In addition to the testimony of Company witness Mr. O'Connor, independent expert witness Mr. Sieracki confirmed the need to proceed in line with the Company's demand forecast:

> The development of a complete design for a program of this magnitude would have taken years and cost many millions of dollars, and if Xcel Energy had waited for the design to be complete, the LCM/EPU Program would not have met Xcel Energy's needs according to the forecasted demand in its resource plan.[168]

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[166] Ex. 9, O'Connor Rebuttal at Schedule 24 at 13.

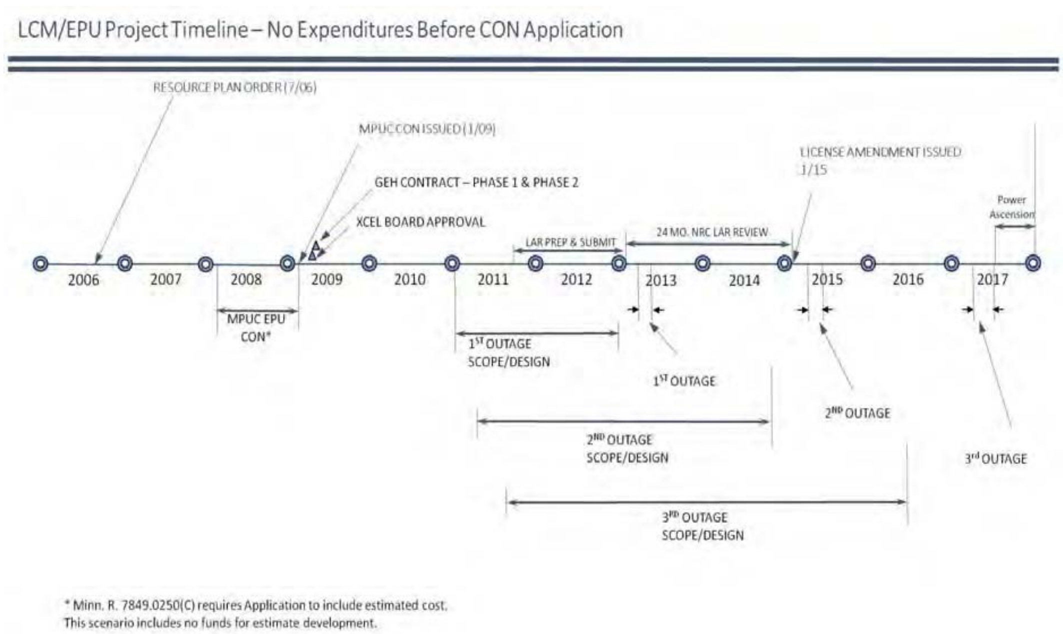
[167] Ex. 9, O'Connor Rebuttal at 53:1 at Figure 2.

[168] Ex. 11, Sieracki Rebuttal at 12:4-8.

Further, as Mr. Sieracki points out from his 40 years of experience in the industry, a multi-track approach is common and often necessary in the industry:

> In addition, it has been my experience that major capital projects in the nuclear power industry often proceed to implementation with only preliminary designs completed. In light of the evolving Nuclear Regulatory Commission ("NRC") regulations and the complexities of working inside an operating nuclear plant, it is very difficult to complete reliable, detailed designs ahead of time. Thus, the concurrent permitting, design, and implementation (i.e., construction) planning approach Xcel Energy took was consistent with many other utilities' experience.[169]

The converse proposition is equally true. The Company could have waited to commence any engineering until after it had obtained the EPU Certificate of Need, rather than spending the $97 million that allowed us to commence construction a mere two months after the permit was issued.[170] That scenario would also have delayed implementation to 2017 as depicted on the following Figure.[171]



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169 Ex. 11, Sieracki Rebuttal at 13:20-14:4.

170 Ex. 9, O'Connor Rebuttal at 52:3-15.

171 Ex. 9, O'Connor Rebuttal at 56:1 and Figure 3.

In sum, if Mr. Crisp's preferred path had been taken, Program implementation would have been substantially delayed, which was inconsistent with the circumstances we faced and would have resulted in a shorter time frame for customers to benefit from our work and a shorter time frame to amortize the costs.

In comparison to our analysis of the alternatives available to us, the Department and OAG are resting on the assumption that costs *might* have been lower if more design had occurred earlier. However, the prudent investment standard requires more than assumptions. *In re San Diego and Electric Co.*,[172] for example, an intervening Party argued that the utility was not "persistent and aggressive in seeking further reductions in capacity and that the utility could have achieved reductions down to a 350 MW minimum" and that therefore all costs in excess of those needed to pay for 350 MW should be disallowed.[173] The commission rejected this high level criticism and assumption of outcomes, finding that:

> [L]ike a plaintiff in a personal injury action who has proved liability but has presented no evidence on damages. Although the general burden of proof remains on the applicant, we believe that [the intervenor's] approach requires them to bear some responsibility for establishing some baseline measure of the results of the prudent behavior they advocate.[174]

Accordingly, that commission concluded it would not make a disallowance "without some indication of what sort of success a utility who had negotiated more creatively would have achieved."[175]

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[172] 31 C.P.U.C.2d at 236. The PUC described this standard as meaning "that at a particular time any of the practices, methods, and acts engaged in by a utility follows the exercise of reasonable judgment in light of facts known or which should have been known at the time the decision was made." 31 C.P.U.C. at 245.

[173] 31 C.P.U.C. at 253.

[174] 31 C.P.U.C. at 253.

[175] 31 C.P.U.C. at 253.

Here, the Parties' assumption that a parallel path approach increased costs is not supported. First, despite raising "substantial questions"[176] in his written testimony, when asked on the stand Mr. Crisp admitted that he was not testifying that the Company's decision to employ a parallel track approach was imprudent.[177] Mr. Crisp also admitted that costs can increase without imprudence.[178]

Second, no witness testified that following a traditional design, bid, build path (where more design is completed up-front) would necessarily have lessened Program cost, nor identified the extent to which costs might have been reduced. Nor do the Parties address the validity of the contemporaneous benchmarking or vendor data on which the Company relied. Rather, Mr. Crisp testified that the Company's parallel-track decision did not "in and of itself" increase Program costs,[179] and disavowed that he was stating any opinion regarding Mr. O'Connor's conclusion that avoiding a multi-track approach was unlikely to reduce costs.[180]

Third, Mr. Crisp candidly admitted that he did not address the reasons for proceeding in parallel fashion, particularly with respect to anticipated baseload demand,[181] and the Department does not contest the demand issues the Company faced through 2009.[182]

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[176] Department Initial Br. at 23.

[177] Tr. Vol. III (Crisp) at 16:8-17:22; *see* Ex. 9, O'Connor Rebuttal at Schedule 1.

[178] Tr. Vol. III (Crisp) at 17:20-22.

[179] Tr. Vol. III (Crisp) at 28:18-21.

[180] Tr. Vol. III (Crisp) at 15:11-17, 18:17-25, 22:7-14, 22:21-23. When asked whether completing more upfront design would have lessened Program cost, Mr. O'Connor referenced a comprehensive explanation of Monticello's design process from a document entitled *The Engineering and Design Process, Xcel Energy Nuclear Department*, and concluded: "I seriously doubt it." Ex. 9, O'Connor Rebuttal at 53:14-54:6 and Schedule 22. And while Mr. Crisp reviewed Mr. O'Connor's explanation, he declined to state an opinion on the propriety of it. Tr. Vol. III (Crisp) at 34:13-19 ("I reviewed it. I'm not certain that I actually opined upon this document.").

[181] Tr. Vol. III (Crisp) at 30:9-18; Ex. 9, O'Connor Rebuttal at Schedule 1.

[182] Department Initial Br. at 70-71.

Finally, the Parties do not rebut the Company's testimony that the initial design scoping was typical of a project proceeding on parallel paths.[183]

Ultimately, no Party in this prudence investigation contests that a parallel track approach was intended to meet the needs of customers and was consistent with nuclear industry standards, or provides industry evidence or specific testimony that costs were likely to be reduced by additional early scoping or design. Rather, the record evidence establishes that the parallel path approach was reasonable under the circumstances.

3. NRC Communications

The Department and OAG Initial Briefs point out that our earlier license extension applications to the NRC did not advise that we also subsequently decided to pursue an uprate, and thereby imply our NRC filings were somehow misleading.[184] However, the record facts are that: (i) in 2005 when we sought the NRC license renewal and the ISFSI Certificate of Need in Minnesota, we had not yet decided to pursue the uprate;[185] (ii) the Company pursued the concept of an uprate with the Commission for the first time in November 2005;[186] (iii) the Company's Board did not approve the uprate until August of 2006, when the ISFSI and license renewal processes were nearly complete;[187] and (iv) the NRC will not entertain simultaneous license

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[183] Ex. 11, Sieracki Rebuttal at 13:20-14:4.

[184] Department Initial Br. at 46; OAG Initial Br. at 4.

[185] Ex. 9, O'Connor Direct at 45:5-6.

[186] Ex. 8, Alders Rebuttal at 8:8-11.

[187] *Compare* Ex. 9, O'Connor Rebuttal at 12:12-13 (Obtained Board approval in August 2006), ***with*** *In the Matter of N. States Power Co. d/b/a Xcel Energy's Application for Approval of its 2005-2019 Res. Plan*, No. E002/RP-04-1752, ORDER APPROVING RESOURCE PLAN AS MODIFIED, FINDING COMPLIANCE WITH RENEWABLE ENERGY OBJECTIVES STATUTE, AND SETTING FILING REQUIREMENTS (July 28, 2006).

applications.[188] Notably, the Company has not come under scrutiny by the NRC for its presentations of future plans for Monticello.

4. Design and Design Modification

The Department and the OAG raise several issues relating to the Company's design process, or "scoping, " and our ultimate designs for the Program. We address those issues below.

a. Design and Project Management

Preliminarily, it is important to clarify the difference between project management and design, as the Department and OAG conflate project management with engineering and design in their Initial Briefs. Project management is defined as follows:

> The term project management is sometimes used to describe an organizational approach to the management of ongoing operations. AACE International, another industry organization, defines project management as the utilization of skills and knowledge in coordinating the organizing, planning, scheduling, directing, controlling, monitoring and evaluating of prescribed activities to ensure that the stated objectives of a project, manufactured product, or service are achieved.[189]

Engineering and design functions, *i.e.*, selecting and integrating the right equipment into the plant, are not included. Those are part of a separate engineering and design process detailed in Schedule 22 to Mr. O'Connor Rebuttal Testimony, and referred to as a "30/60/90/100 percent design review process, which is used in the industry."[190]

Because they confuse project design with project management, the Department and the OAG do not recognize that selecting and integrating the right equipment into the plant is in large part what drove our final costs:

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188 Ex. 9, O'Connor Rebuttal at 21:4-9.

189 Ex. 11, Sieracki Rebuttal at 9:13-19.

190 Ex. 11, Sieracki Rebuttal at 35:2-3; Ex. 9, O'Connor Rebuttal at Schedule 22.

> While project management can assist in managing scope growth and difficult installations, it does not prevent them from occurring. In the end, project management can assist in understanding and managing the costs being incurred, but, particularly in a Project like this, will generally not materially lessen the costs incurred.[191]

More specifically, even a perfect organizational approach with perfect coordination would not obviate the need to complete the work we did. For example, we could not avoid upgrading Monticello's distribution system. The manner in which to best add electrical capacity to the plant, *i.e.*, upgrade to 13.8 kV or try continually patch the old 4 kV system, is an engineering decision rather than a project management decision. Such Program design, rather than project management, were the drivers of the work we ultimately did.

b. Company's Design Approach

Most of the implementation criticisms offered by the Department and the OAG focus on what can be characterized as haphazard early planning and design process. The Department relies on Mr. Crisp to argue that "program design and scope changes were not fully understood or thought out."[192] The OAG relies on Mr. Crisp to support their argument that using preliminary designs was insufficient and "almost guarantee[d] schedule delays and cost overruns during the actual process of construction the project."[193]

The primary problems with these arguments are that they are based on Mr. Crisp's high-level hindsight conclusion that a design-then-bid-then-build approach would have been preferable to avoid changes and develop a more accurate initial cost estimate. However, Mr. Crisp did not assess the specific steps the Company did

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[191] Ex. 11, Sieracki Rebuttal at 30:25-31:4.

[192] Department Initial Br. at 25.

[193] OAG Br. at 28 (quoting Ex. 300, Crisp Direct at 8:3-5).

undertake in its actual design process, nor the additional upfront costs and time such an alternate process would have required (as described and depicted in the Figures in the prior section).

With that said, the Company's design process was robust, incorporated critical elements,[194] and evaluated options that were rejected due to cost and implementation concerns.[195] Specifically, our process began with a review of basic licensing requirements that identified aging equipment that needed replacement and pinch points that limited the ability of the plant to operate at uprated capacity levels. From there, design proceeded into seven district Phases detailed in Mr. O'Connor's Rebuttal testimony, including (summarized here but detailed in testimony) the Study Stage, Design Stage, Design Review Meetings, Challenge Boards, Design Review Boards, Plant Operating Review Committee, and Design Approval.[196]

Throughout each design phase and implementation, we also considered the following four factors to determine how to approach various equipment replacement considerations:

- <u>End-of-Life Considerations</u> – Was the component/equipment at the end of its design life and would continued operation challenge safe and reliable plant operation? Equipment that is at or near the end of its useful life will need to be addressed to support operations through 2030.

- <u>Service-Related Degradation Considerations</u> – Was the component/equipment showing signs of performance degradation to the extent that a maintenance solution was no longer viable for the long term? If equipment showed signs of degradation, through testing or reduction in performance, that equipment would need to be addressed. While repair can be appropriate, replacement is generally preferable to support extended operations for approximately 20 years.

[194] Ex. 9, O'Connor Rebuttal at Schedule 22 at 1-2; Tr. Vol. III (Crisp) at 37:7-39:4.

[195] Ex. 9, O'Connor Rebuttal at 54:1-5 and Schedule 22.

[196] Ex. 9, O'Connor Rebuttal at Schedule 22 at 4-5.

- Obsolescence Considerations – Was the component/equipment no longer supported by its vendor/OEM and/or spare parts sufficiently available to ensure reliable operation? As part of obsolescence, we also considered industry modernization that was taking place to assess whether or not it would have been reasonable to attempt an additional 20 years of operations with outdated equipment. These considerations helped us assess whether repair was feasible or would require custom fabrication and other expensive workarounds, or whether improvements in technology warranted replacement.

- Design/Operating Margin Considerations – Was either the design or operating margin such that the component/equipment represented a threat to safe, reliable operation going forward and for the long-term? We found this factor to be helpful in assessing whether a modification could have been avoided through maintenance.[197]

Throughout all of Mr. O'Connor's testimony and schedules, we provided data on each of these considerations and the Company's approach to addressing them.

During each Phase and with respect to each of the four factors, the fundamental goal of the Company was unchanged: take the steps necessary to ensure a safe work environment and that all equipment and installations will operate safely and reliably.[198] To comply with that goal, NRC requirements dictate that the Company's design process include compliance with a variety of Programs and Rules (including the Corrective Action Program, Aging Management Rule, Maintenance Rule, and RS-001, all detailed in Mr. Stall's Rebuttal Testimony),[199] which further complicate design as specific NRC obligations evolve.

In light of this complex set of considerations and evolving expectations, as well as unforeseeable challenges that simply cannot be identified before construction begins, it is no surprise that we continued to refine our designs as implementation occurred.

[197] Ex. 9, O'Connor Rebuttal at Schedule 32 at 4.

[198] Ex. 4, Stall Direct at 16:12-15; *see* Ex. 3, O'Connor Direct at 13:9-12 and Schedule 3.

[199] Ex. 4, Stall Direct at 17:4-18:24; *see* Ex. 9, O'Connor Rebuttal at Schedule 11 at 8-9.

We discussed these changes in detail throughout our case. In particular, in testimony and schedules we identified where the Company found, through the course of Program work, that some components were more degraded than we understood initially and needed to be addressed regardless of the uprate, including the steam dryer,[200] feedwater heaters,[201] condensate demineralizer system,[202] main power transformer and 1AR emergency transformer,[203] reactor feed pumps and motors,[204] condensate pumps and motors,[205] and PRNM system.[206]

The Feedwater Heaters modification is typical of the time our design process requires and demonstrates it cannot be completed upfront. The initial decision to replace six feedwater heaters was made in 2007.[207] Before the first feedwater heaters were installed in 2011, the seven-step design process, accounting for all four NRC procedures (Corrective Action Program, Aging Management Rule, Maintenance Rule, and RS-001) needed to be complete. It was not possible to complete such detailed processes and procedures by the 2009 outage, let alone by the 2008 Certificate of Need.[208]

Similarly, the Company's designs for the condensate demineralizer necessarily evolved as new issues were identified during Program implementation:

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200 Ex. 3, O'Connor Direct at 103:4-104:4 and Schedule 5 at 1; Ex. 9, O'Connor Rebuttal at Schedule 32 at 18.

201 Ex.9, O'Connor Rebuttal at Schedule 32 at 7; Schedule 34 at 14.

202 Ex. 9, O'Connor Rebuttal at Schedule 32 at 5.

203 Ex. 3, O'Connor Direct at 114:23-115:9; Ex. 9, O'Connor Rebuttal at 90:17-21; 114:7-15 and Schedules 32 at 19-20, 33 at 13 and 34 at 10.

204 Ex. 9, O'Connor Rebuttal at Schedule 32 at 8-9.

205 Ex. 9, O'Connor Rebuttal at Schedule 32 at 10-11.

206 Ex. 3, O'Connor Direct at 99:24-100:6; Ex. 9, O'Connor Rebuttal at 112:21-23.

207 Ex. 3, O'Connor Direct at Schedule 25 at 1.

208 Ex. 11, Sieracki Rebuttal at 34:22-24; *see* Ex. 3, O'Connor Direct at Schedule 25.

> Many parts on the old control system were obsolete. The flow controllers were pneumatic and no longer available. The control for the system was a stepping switch, and that was also no longer available. The plant was able to keep the system running, but spare parts for some items were no longer available. The aggregate issues with the system would have led to replacement of the majority of the system and major maintenance to recoat the tanks, if determined feasible, at some point in the period of extended operations, most likely sooner rather than later.[209]

Like the Feedwater Heaters, the new Condensate Demineralizer System is more efficient, safer, more reliable, and accommodates the increased capacity necessary for uprate conditions.[210] Finally, the replacement of the system avoided a costly and extended shutdown, had the condensate demineralizers failed due to their substantially degraded state.[211] Thus the Company believes that the record evidence supports our approach; even if in hindsight a longer initial design process may have resulted in more accurate up-front cost estimates, it would not have identified all issues and would not have changed the work we ultimately had to complete.

c. Consideration of Alternatives

The OAG alleges that the Company did not sufficiently address the alternatives available to the Company when designing the Program.[212] We detailed some of the options considered in Mr. O'Connor's Rebuttal Testimony, Exhibit 9, Schedules 32 and 35. We summarized the options we considered at pages 40-43 of our Initial Brief and we will not repeat that discussion here.

Notably, however, neither the Department and OAG address the testimony of Mr. Stall, whose entire testimony focused on what the OAG states we did not address:

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[209] Ex. 9, O'Connor Rebuttal at Schedule 32 at 5.

[210] Ex. 9, O'Connor Rebuttal at Schedule 32 at 6-7.

[211] Ex. 9, O'Connor Rebuttal at 56:13-15 (noting that the condensate demineralizers may not have lasted an additional four years).

[212] OAG Initial Br. at 14-18.

> Now, my role was to come in and look at the decision-making that was made for the various scopes of the projects. And to your question earlier, were the right alternatives considered, did they balance safety with cost, did they make the right decisions, and I stepped through that on each of these projects with them and in the end I came to the decision that really they did exactly what they needed to do.[213]

No witness responded specifically to Mr. Stall's Direct Testimony or his substantial discussion of the value of the designs employed by the Company. After reviewing the same material provided to the Department in discovery, Mr. Stall came away with the professional opinion that the Company had designed and installed high-quality designs for the long term betterment of the plant. He concluded:

> [I]n my professional opinion, the quality of the design of the life extension aspects of Xcel Energy's initiative is evidenced by the successful implementation of all of the modifications at the end of the 2013 refueling outage. Only four relatively minor difficulties or refinements are outstanding.
>
> - Despite the difficulties, Xcel Energy obtained a valid and valuable refurbishment of key systems and equipment important to nuclear safety in the 40-year-old Monticello plant for an overall price that is consistent with costs incurred elsewhere.
> - Xcel Energy was able to increase and restore margins and enhance systems necessary to enhance reliable long-term operation.
> - The successful restart to the pre-uprate power level had relatively few issues of concern relating to the initiative, and is indicative of a successful project that demonstrates industry lessons-learned were applied.[214]

[213] Tr. Vol. II (Stall) at 73:2-10.

[214] Ex. 4, Stall Direct at 6:4-19.

When given the opportunity to clarify Mr. Stall's position on issues at the hearing, none of the Parties asked him a single question.[215]

And the Company's records confirm Mr. Stall's opinion. The process we went through in deciding to implement the 13.8 kV distribution system stands out as an example. Schedule 35 to Mr. O'Connor's Rebuttal Testimony (Exhibit 9) is a 77-page analysis and attachments describing the 13.8 kV system, the process we undertook deciding to implement it, the alternatives we considered, and explaining the costs. This analysis stands in stark contrast to the OAG's allegation that we did not consider alternatives. To illustrate the Company's process and diligence, we will summarize the record on the choices we made for this modification and why.

As the LCM/EPU Program was rolling out, the Company determined that adding distribution capacity was required. As even Dr. Jacobs admits, the need for additional distribution capacity was not optional.[216] This resulted in an extended and detailed discussion among the engineers to assess what options were available and what would be most appropriate for the Plant for the long term.

The Company originally examined three main options for the original 4 kV distribution system: replace the original 4 kV system; add capacity to the existing system; or add a new primary power source.[217] These discussions ripened into a formal group presentation called the "Electrical Summit," which was convened to assess alternatives for this critical component. Schedule 35 of Mr. O'Connor's Rebuttal Testimony[218] describes that Summit and its outcome. Attendees at the Summit included site personnel and representatives from General Electric. We

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[215] Unrebutted credible expert testimony should be binding. *See Trisko v. City of Waite Park*, 566 N.W.2d 349, 356 (Minn. Ct. App. 1997), *review denied* (Minn. Sept. 25, 1997).

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

[217] Ex. 4, Stall Direct at 55:12-21; Ex. 3, O'Connor Direct at 131:8-14 and Schedule 28.

[218] Ex. 9, O'Connor Rebuttal at Schedule 35 at 10-16.

evaluated options for feasibility, cost, and schedule impact. The first option involved the replacement of the 1R transformer with a similar design, replacement of the 4 kV breakers with 3305 MVA breakers, and additional bus bracing. The second option involved replacement of the 1R and 2R transformers to supply new 13.8 kV busses to feed the Reactor feed pump, condensate pumps and recirculation MG set motors. The Electrical Summit resulted in a vigorous debate about the pros and cons of these and other options.

Initially, General Electric supported modifying the 4 kV system, but ultimately concluded that "failure to implement the 13.8 kV system would place operating margins of the electrical distribution system at unacceptable levels."[219] We also determined that the cost of upgrading the existing 4 kV system would be essentially the same as adding 13.8 kV capacity.[220] Ultimately, we concluded that a new 13.8 kV bus was the preferred option (over new 4kV or 6.9kV) and would serve the Plant's long-term needs better.

The 13.8 kV system is just one example of the many instances where the Company undertook an active assessment of alternatives. For that reason, the Company respectfully requests that the ALJ and Commission reject the OAG's claim that the Company's assessment of alternatives was inadequate. The evidence in the record demonstrates that the Company reasonably evaluated alternatives before proceeding with the chosen modifications.

d. Planning for Controlling Factors

The OAG and Department also contend that the Company should have started the Program off on a better foot by anticipating and planning for "controlling factors"

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[219] Ex. 9, O'Connor Rebuttal at Schedule 35 at 11.

[220] Ex. 9, O'Connor Rebuttal at 99:12-21 and Schedule 35 at 11.

when designing modifications,[221] including the small Monticello Plant footprint so as to better anticipate work complexities.[222] While the Company did in fact plan for and address "controlling factors" including the small footprint of the Plant,[223] the controlling factors could not be fully assessed until modification design was advanced to the point where engineers and contractors could compare design against the physical limitations imposed by "controlling factors."[224] This is common in the nuclear industry:

> In my opinion it is not feasible to discover all of the "controlling factors" earlier in time because design needs to progress to a sufficiently detailed stage from which the team compares the design to existing plant conditions and, then make assessments about interferences.[225]

For example, the fact that the Company was aware of the small Monticello plant footprint does not obviate the difficulties a small plant footprint presents. As Mr. O'Connor described in response to a question about anticipating the difficulties presented by a small footprint:

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

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[221] Department Initial Br. at 36 (relying on Ex. 300, Crisp Direct at 16-17).

[222] Department Initial Br. at 11, 37; OAG Initial Br. at 29-30.

[223] Ex. 9, O'Connor Rebuttal at 34:16-35:8.

[224] Ex. 11, Sieracki Rebuttal at 5:22-6:5; 34:16-24.

[225] Ex. 11, Sieracki Rebuttal at 34:26-35:8.

> did not provide us with the information necessary to fully appreciate how long the work would take.[226]

This was especially true given that we could not foresee other factors that affected our work in that small space, including the labor pool challenges and the NRC fatigue rule discussed in our briefing and testimony.

e. As-Builts

Both Parties also rely on Mr. Crisp's criticism that the Company should have maintained better as-built drawings to plan for the work as a starting point and to avoid later-discovered conflicts.[227] However, as we explained, Mr. Crisp's criticisms are not grounded in reality. As-builts for the power house side of a nuclear plant of Monticello's vintage (as distinguished from the reactor) were not required to be kept. We explained:

> During the timeframe that first generation nuclear plants were constructed, it was not unusual that the "as built" configuration of non-safety related secondary plant systems were not fully documented on plant drawings, as many of the mechanical systems were "field run" (skilled craft labor determine the installation routing) to facilitate ease of installation. This was in keeping with methodologies used in fossil plants of that era. . . . . At the time the plant was built in the 1960's there was little thought given to the fact that major upgrades would be needed for extending the life of the plant, and it was assumed that the original equipment would last the original 40 years. . . . .
>
> In addition, while we were under no commitment to update the drawings for other non-safety systems, our procedure is that the plant revises drawings when discrepancies are found, which is a way to manage on-going nuclear operations costs. But like many other aspects of the facility many of these had not been mapped to as built drawings over time. This was particularly true of piping installations.[228]

[226] Ex. 9, O'Connor Rebuttal at 46:16-47:2.

[227] Department Initial Br. at 25-26; OAG Initial Br. at 23-25.

[228] Ex. 9, O'Connor Rebuttal at Schedule 9.

Additionally, as discussed on pages 97-98 of our Initial Brief, the 1998 Rerate did not change this fact since there was little construction done on that job and as-builts were not generated.[229] We do not disagree that as-builts would have been helpful, but it cannot be said that the Company was imprudent simply because as-builts were frequently not developed during the era of Monticello's construction and there was no real opportunity to develop them before the Program.

C. Project Management Criticisms

Project management focuses on the "organizational approach to the management of ongoing operations" and "coordinating the organizing, planning, scheduling, directing, controlling, monitoring and evaluating of prescribed activities."[230] It is our belief that project management did not materially affect costs, while the designs we chose and implemented did affect costs as we have described. However, as previously noted, the OAG and Department confuse our engineering and design decisions as project management issues. In this section, we respond to the project management criticisms offered by the OAG and Department.

1. Dedicated Project Team

The OAG criticizes the Company for relying "heavily on contractors to perform the work needed to complete the Monticello Project,"[231] and points out that "it appears Xcel relied on contractors for virtually every action taken to finish the project, other than the decision to start the project and hire contractors."[232]

The overall prudence of the Company's manner of using contractors was addressed by Mr. Sieracki, who concludes that "the initial Project management structure was

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[229] *See* Ex. 11, Sieracki Rebuttal at 32:19-33:13; Ex. 9, O'Connor Rebuttal at 76:12-17.

[230] Ex. 11, Sieracki Rebuttal at 9:13-18.

[231] OAG Initial Br. at 30.

[232] OAG Initial Br. at 30-31.

reasonable and in line with industry norms."[233] Mr. Sieracki further described that not relying on contractors in the manner the Company did would be highly unusual.[234] Because the OAG did not address the Company's reasons for establishing a dedicated project team nor respond with any discussion of industry norms, general statements or implications that the Company was imprudent by utilizing a dedicated project team are not supported in the record.

The OAG and Department utilize the 2011 Cost History to suggest that the Company's decision to utilize and rely upon a dedicated project team for the Program – as opposed to Monticello site staff – was inappropriate.[235] At the outset, we note that the 2011 Cost History does not suggest that any Program costs could have been avoided if the Company had vested project ownership with the site.

With that said, the Company recognizes that who had "ownership" of the Program was an important decision. While having site personnel run the project was certainly an option,[236] there are at least two critical reasons why it was well within the zone of reasonableness for the Company to choose a dedicated project team for the Program.

First, we recognized that Plant operations staff have a full-time job keeping the Plant running safely and it would have been inadvisable to distract them with also managing a major construction project.[237] We believed it was more responsible to keep our site operational team focused on running the plant, not the Program. Choosing a dedicated project team allowed the Plant staff to focus on their primary responsibility

[233] Ex. 11, Sieracki Rebuttal at 26:21-22.

[234] Ex. 11, Sieracki Rebuttal at 27:4-6.

[235] *See, e.g.*, Department Initial Br. at 29-30, 34, 41-42; OAG Initial Br. at 36; Ex. 9, O'Connor Rebuttal at Schedule 24 at 13-14.

[236] This is noted in the 2011 Cost History document, albeit from one individual's perspective rather than the perspective of the final decision-makers. Arguments that the 2011 cost history is a "smoking gun" or evidence of imprudence were addressed and debunked in our Initial Brief at pages 102-104.

[237] Ex. 11, Sieracki Rebuttal at 42:22-24; Ex. 9, O'Connor Rebuttal at Schedule 24 at 17-18.

to ensure safe and reliable operations while allowing the Company to minimize the burden placed on permanent staff.[238] The Company described the thought process behind this decision in greater detail in response to Department Information Requests Nos. 78[239] and 107.[240] In our response to Information Request No. 78, we described:

> The decision was made to manage the project from the Projects Group rather than the site because the Company recognized that the Program was a major initiative that would require dedicated effort and concluded that it was better to manage it as a discrete initiative with separate project management. . . . [T]he LCM/EPU Program required significant major construction modifications to the plant itself and it was the Company's conclusion that it was better to manage such a major construction initiative with a dedicated project structure. In addition, the Company anticipated using contractors such as General Electric as a major source of work for the initiative. As a result, we concluded that it was more appropriate to manage those contractor relationships through the projects organization rather than by the site. The Company also managed the beginning phases of the Prairie Island LCM/EPU and the Steam Generator Replacement project through a separate project organization rather than by the plant.[241]

Second, using a dedicated project team did not mean that site staff were not involved with the Program's development or implementation. As the Company indicated in its response to OAG Information Request No. 6, site personnel were key contributors from 2006 all the way through 2014.[242] For example, site personnel played an important role in advocating for specific work to make the upgrades more user-friendly for our NRC-licensed operators,[243] providing internal Plant resources to help

[238] Ex. 9, O'Connor Rebuttal at Schedule 24 at 20.

[239] Ex. 9, O'Connor Rebuttal at Schedule 24 at 3-18.

[240] Ex. 9, O'Connor Rebuttal at Schedule 23 at 1-6.

[241] Ex. 9, O'Connor Rebuttal at Schedule 24 at 14-15.

[242] Ex. 9, O'Connor Rebuttal at Schedule 28 at 2-3.

[243] Ex. 3, O'Connor Direct at 143:9-10.

complete the 2011 outage,[244] and participating in the decisions.[245] Thus having a dedicated project team was prudent and did not preclude site personnel from having key votes.

2. Contractor Management

The Department and the OAG go on to argue that the Company should have used a more rigorous contractor selection process and did not properly manage the contractors used throughout the Program.[246] Both the Department and OAG rely on the testimony of Mr. Crisp.

Prior to addressing the specific allegations in this criticism, we note that Mr. Crisp does not conclude that our contracting practices were imprudent; rather, the Department believes that Mr. Crisp raised "questions"[247] and suggested that some decisions "likely" lead to cost increases.[248] Again, a mere theoretical conclusion that the Company's actions may have increased costs is not sufficient to sustain a finding of imprudence or impose a remedy.[249] As discussed in our Initial Brief at pages 61-72 and 104-108, the record developed by the Company demonstrates that the Company properly and prudently managed the contractors for the Program.[250] Below we further address the Parties' challenges to the use of contractors.

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244 Ex. 3, O'Connor Direct at 75:24-25.

245 Ex. 9, O'Connor Rebuttal at Schedule 35 at 10.

246 OAG Initial Br. at 30-35; Department Initial Br. at 39-42.

247 Department Initial Br. at 23.

248 Department Initial Br. at 25.

249 *See, e.g.*, *New England Power Co.*, 31 FERC 61,047 at 61,089 n.38 (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers); *Associated Natural Gas Co.*, 954 S.W.2d at 522-523.

250 *See* Ex. 3, O'Connor Direct at 46:16-51:2, 66:13-67:12; Ex. 11, Sieracki Rebuttal at 25:5-31:22; Ex. 314, Campbell Direct Attachments at NAC-4.

a. Contractor Selection

(1) *Use of NMC*

In criticizing which contractors the Company used, the OAG suggests that the Company should not have used the Nuclear Management Company ("NMC")[251] to initially manage the Program.[252] The OAG argues that it is "unusual to see a contractor used as a general manager in the nuclear industry, and that the typical procedure [is] to have a vice president from the utility act as the general manager of such a large construction project."[253] We respectfully disagree with the OAG's characterization and conclusions.

NMC was created as the contract operator of Xcel Energy's nuclear units and for most of its existence also operated six other units in Wisconsin, Iowa and Michigan. NMC was not just the manager of a single project.[254] During its existence, NMC held the operating licenses of its member utilities and operated the plants on behalf of the owners. Xcel Energy was a shareholder in NMC and proceeded with that relationship based on approvals received by the Commission. By 2008, Xcel Energy was the only remaining member of NMC and functionally *was* NMC. At that point the Company decided to disband NMC's business function and absorb its employees and the management of the nuclear plants back into the Company. That transition was

[251] While the Monticello Nuclear Generating Plant has always been owned by Northern States Power Company, at the time the Program commenced, it was operated by NMC under contract with Xcel Energy. *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 2-3 (Feb. 14, 2008). NMC also operated the Company's Prairie Island Nuclear Generating Plant. *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 2-3 (Feb. 14, 2008). The Company represented in the Petition that the reintegration of the functions of the NMC into Xcel Energy was in process and expected to be completed by mid-year 2008, which they were. *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 2-3 (Feb. 14, 2008).

[252] OAG Initial Br. at 33 (citing Tr. Vol. II (Sieracki) at 28:3-15).

[253] OAG Initial Br. at 33.

[254] Ex. 3, O'Connor Direct at 61:4-7.

reviewed by the Commission and was seamless; the same people who worked on the Program at NMC continued to work on it directly for Xcel Energy.

Further, Mr. Sieracki also explains that some companies do hire even wholly independent management companies to operate their nuclear units.[255] The utility will still have people within the company responsible for overseeing the manager.[256] Consistent with proper industry management in this situation, the Company at all times retained oversight of NMC.[257] Thus the OAG's argument about the use of NMC misses the mark.[258]

(2) *Use of General Electric*

The OAG's Initial Brief also criticizes how the Company used General Electric, claiming that "[i]t is also unclear exactly what work GE performed,"[259] and implying that the Company overpaid General Electric.[260] Specifically, the OAG states that "GE did not do the design work, despite being retained as the 'design contractor.'"[261] This criticism is unsupported. The Company provided extensive testimony showing how General Electric was used and why selecting them was prudent.[262]

First, there were many reasons why it was appropriate to select General Electric:

> The fact that General Electric was the original designer of Monticello and its ample financial and operational record were the primary reasons for our choice. . . . General Electric holds proprietary rights to aspects of

[255] Tr. Vol. II (Sieracki) at 28:3-15.

[256] Tr. Vol. II (Sieracki) at 28:9-15.

[257] Tr. Vol. II (Sieracki) at 24:13-15, 30:16-24.

[258] Ex. 11, Sieracki Rebuttal at 27:18-24.

[259] OAG Initial Br. at 31.

[260] OAG Initial Br. at 31.

[261] OAG Initial Br. at 31.

[262] Xcel Energy Initial Br. at 62-63, 87; Ex. 3, O'Connor Direct at 45:5-15, 47:8-49:3, 55:6-12; Tr. Vol. I (O'Connor) at 108:17-21.

> the design basis at Monticello, and it was most efficient to use their prior knowledge and experience for this work.
>
> Further, General Electric previously prepared and received approval for a series of license topical reports that are a roadmap for generally completing the technical analyses necessary to complete a license amendment request for an EPU. . . . Those reports were previously reviewed and approved by the NRC, and it is more cost-effective to rely on these reports, by obtaining the necessary license, rather than recreate this information with a third Party.
>
> Finally, the agreement with General Electric permitted the use of subcontractors to supplement its expertise and gain access to specialists in the design and manufacture of certain components.[263]

Besides General Electric depth of experience, "GE's calculations for previous power uprate projects have demonstrated to the NRC that GE's boiling water reactors can operate within safety margins."[264] In addition to these benefits, General Electric is simply the vendor who the industry uses for this work:

> As of December 2007, the NRC had completed 114 power uprate project reviews. This has resulted in approximately 4,914 additional MW for our nation's power supply grid. GE is the lead vendor for the power uprate projects for boiling water reactors and has been the primary engineering firm for each power uprate. Appendix E contains a list of the power uprates approved by the NRC. [265]

In light of these facts and Mr. Crisp's acknowledgement that reliance on General Electric was "absolutely" reasonable,[266] it was reasonable for the Company to select and use General Electric.[267]

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[263] Ex. 3, O'Connor Direct at 47:21-48:31.

[264] *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 3-16 (Feb. 14, 2008).

[265] *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING at 3-13 (Feb. 14, 2008).

Second, the work General Electric performed was detailed in the record. Mr. O'Connor's Direct Testimony shows that General Electric was involved with a majority of the major modifications, including the Turbine Replacement, the Power Range Neutron Monitor, the Condensate Demineralizer System Replacement, the Main Power Transformer, the 1AR Emergency Transformer, the Feedwater Heaters, the Reactor Feedwater Pump, the Condensate Pump and Motor, the 13.8 kV Distribution System, and the EPU License Development.[268]

(3) *Use of Day Zimmerman*

The OAG also argues that many cost increases could have been avoided if the Company had engaged in a more rigorous or competitive contractor selection process.[269] However, the OAG does not identify evidence to suggest what a more rigorous selection process would look like, or in what manner the Company's selection process was deficient. For instance, no Party suggested who should have been hired other than General Electric, Day Zimmerman or Bechtel at the times we made those decisions.

Conversely, the record shows that the Company engaged in a rigorous Request for Proposals ("RFP") for an implementation contractor, consistent with common industry practice.[270] To increase the odds of receiving thorough and responsive proposals, the Company specifically targeted and solicited responses from five known and experienced nuclear industry vendors: Bechtel Corporation, Areva NP, General

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

[267] *Gulf States Utils. Co.*, 578 So. 2d at 85 (citing *Metzenbaum*, Opinion No. 25, 4 FERC 61,277, 26 P.U.R.4th 144) (standard calls for reasonable decisions, not perfection).

[268] Ex. 3, O'Connor Direct at Schedule 6.

[269] OAG Initial Br. at 31 and 34.

[270] Xcel Energy Initial Br. at 63-64; Ex. 3, O'Connor Direct at 49:24-50:10; Ex. 11, Sieracki Rebuttal at 45:5-46:3.

Electric/Shaw, Sargent & Lundy, and Day Zimmerman.[271] Only two responses were received: one from General Electric/Shaw and one from Day Zimmerman working with Sargent & Lundy.[272]

> We received two responses to the Request for Proposals; one each from the consortiums of General Electric and Shaw and of Day Zimmerman and Sargent & Lundy. Neither bidder was willing to entertain the earlier General Electric installation estimate, rather they made proposals based on their own updated analysis. Both proposals involved time-and-materials-type pricing structures. Two other candidates elected not to provide a proposal. We performed a quantitative and qualitative assessment of both proposals and selected the joint bid of Day Zimmerman and Sargent & Lundy. We subsequently issued a release to Day Zimmerman in December 2007, for work planning and installation services.[273]

The Company reasonably selected Day Zimmerman for two reasons.[274] First, the Company's review of the RFP responses favored Day Zimmerman on both cost and non-cost bases, including its implementation abilities.[275] Second, we recognized that installation was not in General Electric's 'wheelhouse.'[276] In fact, Generic Electric recommended someone other than them perform the implementation work.[277] So while General Electric was appropriate as the original manufacturer with specific design and licensing information and experience, it was reasonable to select Day Zimmerman as the installation contractor.

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[271] Ex. 3, O'Connor Direct at 49:24-26.

[272] Ex. 3, O'Connor Direct at 50:1-3.

[273] Ex. 3, O'Connor Direct at 50:1-10.

[274] *In re Citizens Communic'ns Co.*, 220 P.U.R.4th 280 (Vt.P.S.B. 2002); *Nat'l Fuel Gas Distrib. Corp. v. Pub. Serv. Comm'n of N.Y.*, 947 N.E.2d 115, 120-21 (N.Y. 2011) (reasonableness should be based on what was known or reasonably knowable at the time).

[275] Ex. 3, O'Connor Direct at 50:6-8.

[276] Tr. Vol. III (Crisp) 36:17-25; Tr. Vol. I (O'Connor) at 107:15-23.

[277] Tr. Vol. I (O'Connor) at 107:15-25.

b. "Starts and Stops"

The OAG and Department also criticize our changes in contractors as decisions that potentially increased costs. The Department argues that the Company's poor management led to contractor changes[278] and refers to Mr. Crisp's characterization of contractor changes as disjointed "starts and stops."[279] While we address Mr. Crisp's "starts and stops" criticism in our Initial Brief, we note here that Mr. Crisp never concluded "as to the reasonableness at the time of any particular event [change in contractors]."[280] Similarly, the OAG notes that "there are many valid reasons to replace a contractor."[281]

The critical question is not solely whether a change in contractors increased costs, but whether the original contractor selection and subsequent decision to change contractors were each prudent decisions based on all information known at the time – including costs.[282] We have previously discussed in our Initial and Reply Briefs why the record evidence illustrates that selection of Day Zimmerman as the lead implementation contractor for the 2009 outage (and continuing through the 2011 outage) was a reasonable decision.

We believe we have established that the major contractor change – hiring Bechtel for the 2013 outage – was a prudent manner of project management. As the Company was completing the more-difficult-than-expected 2011 outage and commencing preparations for the 2013 outage, we were presented with two alternatives: stay the course with Day Zimmerman or retain Bechtel (who had recently come on board to

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278 Department Initial Br. at 39-40.

279 Ex. 300, Crisp Direct at 20:7-9.

280 Department Initial Br. at 39.

281 OAG Initial Br. at 34.

282 *See Potomac Elec. Power Co.*, 661 A.2d at 141-42; *State ex. rel. Associated Natural Gas Co.*, 954 S.W.2d at 530 (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers).

do other work for the nuclear department).[283] We followed a rigorous process to assess whether a new contractor should be retained for the 2013 installations.[284]

As Mr. O'Connor testified, we determined that the 2013 implementation work required a "different kind of skill set,"[285] which ultimately led to hiring Bechtel:

> In 2011 the primary focus of that outage was, I would say, primarily mechanical-related work, pipe, tanks, valves, tubing, that kind of thing. And the primary focus during that outage was the condensate demineralizer system. That's what the focus was. The contractor or the installer that was selected [Day Zimmerman] was very good at that kind of work scope, because that's the scope we were doing; that was the primary purpose of the outage. So we hired who we believed to be the best to do that kind of work, meaning we didn't hire somebody who could do more than that, we didn't hire someone who could do less than that.
>
> As we finished 2011 and then said, well, what's left, we started looking at, well, we've got this time mechanical, electrical -- huge electrical, a lot of instrumentation, and a lot of testing now in integrated operations on all of these systems. That's a different kind of skill set. And so what we believed is we needed now someone who had more that type of experience, which is why we went to Bechtel. And, as you know, Bechtel is an industry expert at that kind of, what I call, larger scale integrated activities and testing. And so we brought them in because that was the next, what I would say, phase; and we brought in the expertise then to accommodate what that phase required.[286]

Notably, the OAG does not argue against hiring Bechtel, but rather contends that the Company erred by not hiring Bechtel sooner.[287] This argument again misreads the

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283 Ex. 9, O'Connor Rebuttal at 69:12-13.

284 Ex. 3, O'Connor Direct at 83:10-20.

285 Tr. Vol. I (O'Connor) at 98:7.

286 Tr. Vol. I (O'Connor) at 97:13-98:15.

287 OAG Initial Br. at 33.

record, which established that Bechtel declined to participate in the original 2007 RFP process for earlier implementation work.[288]

More importantly, the Company simply needed two different skill sets to complete the 2011 and 2013 outage work. As such, it was well within the "zone of reasonableness" to bring in different contractors to meet those needs:

> Xcel Energy demonstrated prudent management by directing and controlling external resources. Removing a contractor when it became clear that another contractor would be able to do a better job and had more targeted expertise is not a sign of imprudence but is a sign of proactive oversight.[289]

Finally, there is no evidence that contractor changes in fact impacted final costs. The Company specifically assessed the efficiency of the 2011 versus the 2013 outages, and found no material difference.

Because the work needing to be completed following the 2011 outage suggested that the final implementation would be significant[290] – and indeed the 2013 outage turned out to be the most difficult and expensive of the overall effort[291] – we did a specific "outage efficiency analysis"[292] to compare the 2011 outage effort with the 2013 outage

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[288] Ex. 3, O'Connor Direct at 49:24-50:3; Ex. 11, Sieracki Rebuttal at 43:24-44:3. Since Bechtel declined to bid for the work originally, Xcel Energy can hardly be blamed for not hiring them sooner. *See Kuhl v. Heinen*, 672 N.W.2d 590, 593 (Minn. Ct. App. 2003) (stating that the duty to exercise care is dictated by the exigencies of the occasion, and if no harm is foreseeable, there can be no negligence); *In re GPU, Inc.*, 96 Pa. P.U.C. at 91-92.

[289] Ex. 16, O'Connor Surrebuttal at 19:9-13; *see* Ex. 11, Sieracki Rebuttal at 47:13-15. The Company also prudently changed contractors when doing so was necessary to ensure the work we did was appropriately scaled. In 2010, for example, the Company changed vendors on a portion of the piping work for the reactor feed pumps and motors modification. The original design from Shaw (working via subcontract with General Electric) required removing and rerouting over 290 feet of piping. Based on our oversight of this design, we determined it was not reasonably constructible and chose a new vendor with expertise in the area to produce a final design that required removal and rerouting of only 60 feet of piping. This single change saved approximately $6.6 million in installation costs and avoided delaying the outage in order to install extraneous piping. In short, the Company worked in good faith and within careful processes and the available resources to ensure we had the right contractors working on the Program at the right times.

[290] Ex. 9, O'Connor Rebuttal at 67:3-11.

[291] Ex. 9, O'Connor Rebuttal at 70:13-16 and Schedule 26 at 6.

[292] Ex. 9, O'Connor Rebuttal at 73:18-75:5.

for signs of imprudence. In particular, our question was whether we could discern a meaningful distinction in the efficiency of the installations between the two outages.

We compared the preparation and in-outage costs for both the 2011 and 2013 outages and found the daily 'burn rate' to be virtually identical. This comparison illustrates that our adjusted per outage day costs were about the same for the 2011 outage to the 2013 outage.[293] The following table illustrates the calculation:

Comparison of the 2011 and 2013 Outage Costs

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

As Mr. O'Connor observed:

> Bechtel spent substantially more time planning for the outage and managed their implementation costs downward but their efficiencies came with a cost. I think this illustrates that there were not costs that could be readily saved by differing approaches to Project implementation.[294]

Rather than showing signs of "starts and stops" or a disjointed or disorganized implementation, the 2011 and 2013 outages ended up costing about the same on a dollars per day basis,[295] an indication that our performance was consistent across both outages and that there were not costs that could be readily saved by differing approaches to implementation.

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[293] Ex. 9, O'Connor Rebuttal at 74:7-22.

[294] Ex. 9, O'Connor Rebuttal at 74:7-22.

[295] Ex. 9, O'Connor Rebuttal at 74:16 at Table 7.

c. *Contractor Oversight*

In addition to challenging the Company's selection and utilization of contractors, the Department and the OAG generally assume inadequate "oversight and project management controls" over the implementation of the initiative.[296] In contrast, we provided significant information about project management and project controls that we implemented.[297] As Mr. O'Connor describes:

- We established a series of core principles that guided implementation. Many of these controls around engineering and quality worked well. Our project controls were consistent with other projects within the nuclear department.
- Our vendor contracts include an orderly process for change orders.
- We require vendors to develop and implement recovery plans to overcome performance issues that arise during implementation.
- We employed an internal project manager to lead the Company's LCM/EPU team and to oversee our key vendors, General Electric (design/engineering) and Day Zimmerman (initial installations).[298]

In addition, the nuclear oversight function at the Company was described as follows:

> **Nuclear Oversight** is responsible for Nuclear's quality assurance and corrective action programs. This area is responsible for establishing, maintaining, and interpreting Xcel Energy's quality assurance policies and procedures; establishing the requirements for assessor and inspector certification; managing the overall independent assessment process and establishing quality control practices and policies for quality verification activities. Additionally Nuclear Oversight provides for supplier evaluation; the conduct of supplier assessments or surveys (including their sub-tier suppliers); and verification that supplier quality assurance

[296] Department Initial Br. at 40; *see* OAG Initial Br. at 34.

[297] Ex. 9, O'Connor Rebuttal at 37:11-18, 66:16-25.

[298] Ex. 3, O'Connor Direct at 47:14-16; Ex. 9, O'Connor Rebuttal at 66:23-25.

> programs comply with Xcel Energy requirements. This organization has the authority to stop work at the sites and headquarter offices.[299]

Within the Nuclear Oversight function, we took several steps to ensure Program management was as effective as possible.

First, we created a dedicated project management team to carry out these functions.[300] We set our internal staffing levels appropriately to ensure we had adequate coverage to allow for proper oversight.[301] We evolved our oversight practices to adapt to changing circumstances.[302]

Second, we established and used a number of internal review committees that provided oversight of the design effort. These committees met regularly to approve scope changes, manage vendor performance and address design questions.

As part of our active oversight, we rejected several key components in this process. One notable example was related to the condensate pump and motor modification. Our vendor had difficulty meeting our design specifications, so we proactively required the vendor to modify the design. Ultimately the vendor resolved the issue and delivered equipment that met our specifications.[303] Such critical assessments of contractors further illustrate the Company's prudent contractor management.

Third, we interfaced with our external design organizations to oversee vendor services, such as communications, work processes, scope of work and task authorizations and design control.[304] As described elsewhere, our proactive

[299] Ex. 3, O'Connor Direct at Schedule 14 at 2.

[300] Ex. 3, O'Connor Direct at 60:24-25 and Schedule 14.

[301] Ex. 3, O'Connor Direct at 47:13-16.

[302] Ex. 3, O'Connor Direct at 63:14-27.

[303] Ex. 3, O'Connor Direct at 128:21-129:5.

[304] Ex. 3, O'Connor Direct at 66:13-18.

contractor management included occasionally moving design work to other vendors.[305] Our internal oversight of vendors required additional review and analysis and added on-site inspections of equipment that had failed to meet specifications.[306]

Fourth, another example of our active project oversight that is not addressed in the Parties' Initial Briefs or testimony is our robust Quality Assurance and Quality Control ("QA/QC") function, which was specifically applied to this Program. QA/QC requirements are placed on nuclear utilities by the NRC under 10 CFR Part 50, Appendix B. This function requires us to make site inspections, audits and oversight of our contractors throughout the course of the work. Our QA/QC function reviewed our work products, design activities and the goods and services that we procured from our vendors.[307]

Fifth, in accordance with industry standards, we implemented and followed key outage planning milestones, including scope identification, work package planning, procurement, work order walk downs and schedule preparation and refinement.[308] When vendor or other issues arose that put milestones at risk we developed recovery plans:

> To develop these plans, we identified the reason for slippage, the effect on successor cascading milestones, plans to communicate the risk of slippage for successive work in other departments that may be impacted and courses of action to recover and meet the milestone.[309]

Sixth, we developed and implemented detailed scheduling and work-flow protocols. Our contractors were responsible to oversee their workforce, including the logistics of

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[305] Ex. 9, O'Connor Rebuttal at 63:1-8 (replacing contractor resulted in $6.6 million saving).

[306] Ex. 3, O'Connor Direct at 66:24-26.

[307] Ex. 3, O'Connor Direct at 67:3-12.

[308] Ex. 3, O'Connor Direct at 69:6-11.

[309] Ex. 3, O'Connor Direct at 69:22-26.

managing hundreds of craft laborers on the sight 24-hours per day during outages. To coordinate with the contractors, we used computerized scheduling tools to schedule activities among our contractors and their workforce to minimize disruptions and increase efficiency to the extent feasible.[310] Rather than lacking oversight, the Company's management of its vendors was proactive and consistent with industry standards.

It is worth noting that neither the Department nor the OAG articulates a deficiency or inadequacy with any of these issues. Instead, the OAG argues that the Company "has not produced any evidence that it managed its contractors reasonably given all of the challenges it faced during the Project,"[311] and that the Company failed to explain how it "came to have so many problems with its contractors given all of the 'oversight' it had."[312] The OAG then goes on to suggest, without citation, that the Company's "many problems" were that "GE was not provided enough information to do a good job in its design work; poor performance on the part of Day Zimmerman led to transferring the work to other contractors; and Xcel ultimately had to turn to yet another major contractor just to get the Project even close to finished."[313]

It is not clear why the OAG discusses the transfer of work from Day Zimmerman and turning to another major contractor as two separate things; as discussed in more detail below and in our Initial Brief at pages 107 to 108, Bechtel was retained for the final work in the 2013 outage due to the differences between the work done in the 2011 vs. 2013 outages. Moreover, the OAG (like Mr. Crisp) "is silent on the fact that

[310] Ex. 3, O'Connor Direct at 87:3-4.

[311] OAG Initial Br. at 34.

[312] OAG Initial Br. at 35.

[313] OAG Initial Br. at 35.

Day Zimmerman remained on the job as the primary mechanical subcontractor for the 2013 outage.[314]

We believe the OAG's claims are misplaced. As previously discussed, Bechtel was retained for the final work in the 2013 outage due to the differences between the work done in the 2011 vs. 2013 outages. Moreover, the OAG (like Mr. Crisp) "is silent on the fact that Day Zimmerman remained on the job as the primary mechanical subcontractor for the 2013 outage."[315] As it pertains to General Electric, the record is clear as to the role they played in the Program. General Electric played the role it was intended to play – designer – and properly interfaced with our installation contractors to facilitate completion of the work.

d. Potential Vendor Claims

The OAG also asserts that the mere existence of contractor difficulties is a sign of mismanagement on our part.[316] The OAG intimates that not only were we supposed to be perfect, but we are also imprudent if our contractors were not perfect. We disagree. The Company cannot be expected to ensure perfection from all contractors at all times; rather, the purpose of contracts is to incent proper work and provide remedies in the event proper work is not provided. In a major construction project of this magnitude, particularly in the highly complex nuclear industry, vendor disputes are unavoidable.

The Company at all times has sought to enforce our contracts and pursue remedies where appropriate. Rather than a sign of imprudence, this shows us to be proactive managers trying to protect our rights where appropriate. The disputes, the amounts in issue and a description of the pending and settled claims are identified in our Trade

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[314] Xcel Energy Initial Br. at 107-08 (citing Ex. 11, Sieracki Rebuttal at 48:21-23; Ex. 9, O'Connor Rebuttal at 47:16-18).

[315] Xcel Energy Initial Br. at 107-08 (citing Ex. 11, Sieracki Rebuttal at 48:21-23; Ex. 9, O'Connor Rebuttal at 47:16-18).

[316] OAG Initial Br. at 36.

Secret response to OAG IR-5 (Ex. 203, Schedule JJL-2). These claims and their resolution are a sign of our proactive management and our good faith attempt to enforce our contracts for the benefit of ratepayers.[317]

3. Overall Alleged Mismanagement

The OAG asserts that the Company's performance reveals "an interrelated web of mismanagement."[318] Similarly, the Department asserts that their consultants "identified many decisions and actions including poor project management by Xcel that were not reasonable at the time."[319] This flatly contradicts the Department's acknowledgment that Mr. Crisp did *not* "opin[e] as to the reasonableness at the time of any particular event."[320] In addition to being unsupported by record evidence, these assertions unfairly misunderstand the self-critical nature of the nuclear environment and the premium on always striving to get better. "The focus on safety and reliability demands that a utility adapt, evolve and continually strive to get better. Far from a sign of imprudence, it is expected that utility managers review recently completed work efforts and probe how they can perform better in the future."[321]

No work on a complex nuclear project is ever perfectly understood in advance; therefore, "lessons learned" are an important aspect of prudence project management.[322] Indeed, the 2011 Cost History (that the Parties rely on) is actually an application of this appropriate self-critical process. In itself, this proactive self-assessment is a further example of prudent Program management. Our employees are

[317] Finally, we preserved, pursued and resolved claims recognizing that any value received should be an offset to the cost of the Program. Claims that have already been settled have been accounted in this way, and we have committed to account for any future settlement or awards arising from vendor disputes as offsets to the Program cost so that ratepayers will receive the benefit.

[318] OAG Initial Br. at 36.

[319] Department Initial Br. at 9.

[320] Department Initial Br. at 39.

[321] Ex. 4, Stall Direct at 26:7-10.

[322] Ex. 4, Stall Direct at 15:19-16:2; Ex. 9, O'Connor Rebuttal at 72:18-23; Ex. 11, Sieracki Rebuttal at 29:9-11.

encouraged and indeed expected to be critical and to question to ensure all points of view are expressed to help foster nuclear safety. That culture should not be held against us:[323]

> Far from a sign of imprudence, it is expected that utility managers review recently completed work efforts and probe how they can perform better in the future. This is also an NRC requirement and is best described as the corrective action program. The self-critical approach utilized in the industry coupled with a credible regulator is the main reason for the high levels of safety and performance in the U.S., among the best in the world.[324]

This questioning and self-critical process is important and was used to improve the Program. For example, during the 2006 review, as part the Company's benchmarking process, the Company looked at lessons learned at other BWRs.[325] This helped us develop the programmatic controls described earlier.[326] Further, after each outage the Company developed lessons learned evaluations.[327]

These post-outage lessons learned evaluations helped identify areas the Company could improve. But rather than see these evaluations as negative, the willingness to be self-critical and to challenge ourselves to do better are examples of proactive and prudent management, where the Company recognized room for improvement and made changes during the Program to improve Program operations.[328]

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323 Ex. 4, Stall Direct at 26:7-14; Ex. 9, O'Connor Rebuttal at 72:21-23.

324 Ex. 4, Stall Direct at 26:7-14.

325 Ex. 9, O'Connor Rebuttal at 37:3-7.

326 Ex. 9, O'Connor Rebuttal at 37:9-18.

327 Ex. 9, O'Connor Rebuttal at 72:3-8.

328 Ex. 3, O'Connor Direct at 74:25-75:2; Ex. 11, Sieracki Rebuttal at 29:9-18.

4. Additional Program Impacts

While the Parties are critical of our project planning and implementation, they do not challenge the fact that the complexities we identified existed or that our cost increases associated with installation were real. In addition, the Parties fail to acknowledge the following additional reasons costs increased.[329]

a. Craft Labor

The Parties do not dispute that our challenges with employing an adequate craft labor pool were unforeseeable, as the reductions in the available labor pool did not occur until 2010 and 2011. As our costs increased beyond expectations during the 2011 outage, we were concerned that this could have been a sign of a shortcoming on our part. As we investigated the issues during the 2011 outage, we discovered that the experience of our craft labor had fallen off dramatically due in large part to competition from new hydraulic fracturing work and other industrial work sites that could hire workers without the restrictions inherent in working at a nuclear plant:[330]

> There was a trend of less experienced or new nuclear craft labor during our Program. In 2009, I estimate that 90 percent of our craft supervision and labor were nuclear-experienced. In 2011, I would estimate that number declined to 45 percent. This and the complexity to finish the remaining aspects of the Program necessitated changes for the 2013 outage.[331]

b. NRC Impacts

In addition, our NRC licensing process extended from one to five years and roughly doubled from $28.6 million to about $60 million.[332] While the Department disputes

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329 *See Kuhl*, 672 N.W.2d at 593 (stating that the duty to exercise care is dictated by the exigencies of the occasion; *In re GPU, Inc.*, 96 Pa. P.U.C. at 91-92.

330 Ex. 9, O'Connor Rebuttal at 36:6-8.

331 Ex. 9, O'Connor Rebuttal at 69:14-19.

332 Ex. 3, O'Connor Direct at 34:21-25.

that the NRC licensing process increased our capital cost,[333] there is no dispute that the direct licensing costs themselves roughly doubled. A licensing process that drags on for so long is going to have indirect effects on the overall effort. Nor can there be any dispute that such events, beyond the ability of a utility to foresee or control, cannot serve as a basis for a finding of imprudence.

The Parties' Initial Briefs also ignore the indirect impacts we encountered through increasingly strict NRC compliance.[334] This issue is not one of attempting to "blame"[335] the NRC, but is rather just a reflection of the reality that as NRC requirements increase, the difficulty and cost of our work necessarily increase. We describe the impacts of these requirements on pages 45-47 of our Initial Brief. Notably, the unforeseeable "fatigue rule" dramatically increased our costs in the later outages, as we were required to retain additional workers to overcome the limitations from this rule. The operation of this new rule created a significant loss of productivity as we had an increasingly difficult time holding on to qualified workers.[336]

It is important to recognize these drivers of cost increases in addition to the ample evidence of the expanded work we determined was necessary for the major modifications of the Program. Absent acknowledgement and recognition of the unavoidable and unforeseeable drivers of cost increases, it is all too easy to simply claim that cost increases must have resulted from imprudence. We submit that a more balanced and methodical reading of the record illustrates that no imprudence

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333 Department Initial Br. at 46.

334 Ex. 9, O'Connor Rebuttal at 24:9-10; Ex. 4, Stall Direct at 17:13-18:24. These requirements include: (i) Corrective Action Program; (ii) Aging Management Rule, 10 CFR Part 54.21 (2014); (iii) Maintenance Rule, 10 CFR Part 50-65 (2014); (iv) NRC Review Standard RS-001 for extended power uprates; (v) the Back Fit rule and the Forward Fit concept as applied by NRC staff and (vi) Fatigue rule, 10 CFR Part 26 (2014).

335 Department Initial Br. at 46.

336 Ex. 3, O'Connor Direct at 91:20-92:5.

occurred, that we built the right project, and that customers are benefiting from that work and the efficiencies of implementing an integrated Program.

5. We Completed the Right Project

Relying on Dr. Jacobs, the Department suggests that we did not need to do much of the work absent the uprate.[337] We disagree and believe the record is clear that the work was necessary to meet the long-term needs of our customers. For example, Dr. Jacobs admits that the distribution system was already in need of significant work due to under voltage alarms.[338] He admitted that the feedwater heaters are components that normally need to be replaced for life extension irrespective of the uprate.[339] And he candidly admits he made no study of the condition of the components generally.[340]

Mr. Stall's testimony summarizes the need for the work and the benefits of the approach the Company took:

> Xcel Energy's approach appropriately combined attributes of a prudent life-cycle management to maximize the 20-year license extension with a prudent uprate plan necessary to achieve the added capacity once the EPU license amendment is granted. I am supportive of designing a program that addresses both life extension and the increased capacity simultaneously as this is a more efficient way to implement upgrades and also reflects the practical reality that many upgrades in a 40-year-old power plant will need to be made at some point. It provides good economies of scale and synergies to implement those upgrades along with the installations necessary to support the uprate. By doing the upgrades in the same timeframe, you create an integrated design for the project with fewer future modifications required than if portions were installed over a longer timeframe.

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[337] Department Initial Br. at 48 (13.8 kV system not needed absent uprate) and 56 (general LCM would be different absent the uprate).

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

[339] Tr. Vol. IV (Jacobs) at 29:10-14.

[340] Tr. Vol. IV (Jacobs) at 36:11-15.

> The LCM capital project replaced obsolete instruments and controls in several critical plant control systems. In many cases, dated analog technology was replaced with digital technology. Maintenance costs increase as the equipment ages. The old equipment utilized largely obsolete technology that required special training. Additionally, many parts are not available and custom refurbishment of existing parts is necessary. New modern control equipment will minimize the potential for extended plant shutdowns, maintain plant reliability, and reduce ongoing maintenance costs.[341]

When the Department's challenges arose in this case, we provided a considerable amount of information about the benefits of the work we did. We provide a listing of the benefits to customers and the Plant in our testimony that we describe in our Initial Brief at pages 12-13. In addition, the record reflects many other benefits from the work we did. For example:

- The 13.8 kV system provides benefits gained by splitting the safety system loads from the non-safety system loads.[342] This not only provided desirable redundancy but also increases the operating margin of our remaining 4 kV safety busses.[343]

- The condensate demineralizer system more efficiently removes fine debris and resin from the condensate and as a result we expect reduced operations and maintenance costs.[344]

- The new steam dryer is more efficient at removing moisture from the steam produced and lowers the operating and maintenance costs.[345]

- Replacing the PRNM system with a state-of-the-art digital system. There are also life-cycle benefits to moving to digital equipment improves system performance. Specifically, digital reads are more

[341] Ex. 4, Stall Direct at 35:10-36:3.

[342] Ex. 9, O'Connor Rebuttal at 96:20-21.

[343] Ex. 9, O'Connor Rebuttal at 100:15-16.

[344] Ex. 9, O'Connor Rebuttal at 6:23-25.

[345] Ex. 3, O'Connor Direct at 143:26-144:2.

frequent, more accurate, and respond easier to changing conditions in the core.[346]

- The new design breakers chosen for the distribution system upgrade have many benefits over the old air-magnetic breakers, especially in the scope of maintenance. Vacuum breakers require much less maintenance as there are fewer moving parts, and the arcing contacts are contained within a sealed vacuum bottle.[347]

- The feedwater heater installations reduce operations and maintenance expenses and all of the associated work provides benefits to the operations of the plant at pre-uprate levels as well as uprate levels.[348]

- Replacing the existing HP turbine with a turbine with an Advance Vortex design provides superior reduction on secondary losses and profile losses and also allowed us to overcome a worrisome vibration issue we had on the turbine floor.[349]

- Replacing the condensate demineralizer system allowed us to reduce the frequency of needing to recharge the filter elements and upgrading the control system provided benefits to our operators. Further, this upgrade allowed us to address water quality issues with the potential to lower Monticello's availability.[350]

- The replacement of the reactor feed pumps and motors allowed the plant configuration and operations to remain consistent during the extended life. This "two-pump solution" has saved countless hours of procedure revisions and operational training. Reliability has improved by addressing and eliminating wear conditions that necessitated preventative and corrective maintenance of this equipment.[351]

It is true that we accelerated some of our work as compared to the last possible time it could be completed; however, this did not make the work unnecessary, unavoidable

[346] Ex. 9, O'Connor Rebuttal at 113:25-27.

[347] Ex. 10, O'Connor Rebuttal at Schedule 32 at 33 (Non-Public).

[348] Ex. 3, O'Connor Direct at 121:12-13.

[349] Ex. 9, O'Connor Rebuttal at 103:10-15.

[350] Ex. 3, O'Connor Direct at 111:14-20.

[351] Ex. 3, O'Connor Direct at 126:9-14.

or unreasonable.[352] All of this work needed to be done anyway so it was appropriate to bundle the work together on the various systems:

> It was prudent to replace components as part of the LCM/EPU Program because it minimized the need to make major investments later on during Monticello's extended life to ensure reliability. Also, by combining this work with the LCM/EPU Program, we were able to achieve economies of scale and eliminate the need to go back to the same system to make additional modifications. Finally, replacing some components ahead of schedule allowed us to get more use out of the component and maximize the depreciation schedule for these significant investments.[353]

We also faced a significant ratemaking issue. Given the duration of the Company's extended license, delaying replacement would have increased costs and would not have maximized the depreciation schedule for these substantial investments.[354] Twenty years is not a long time to depreciate major power plant costs and delaying implementation would have shortened the pay-back period, thereby exacerbating the ratemaking impact. Such acceleration is appropriate, as even Dr. Jacobs acknowledged that this acceleration has the benefit of minimizing costs and maximizing the depreciation schedule.[355]

In sum, our Program management reflects reasonable actions and decisions in highly complex, evolving circumstances. The Company made prudent decisions based on the facts and choices available, proactively managed the Program and its personnel to the greatest extent possible, and reacted properly to issues we could not have foreseen and for which we could not have planned. We also took proactive measures to ensure our contractors did the work properly, and reacted appropriately in the circumstances

[352] Ex. 3, O'Connor Direct at 36:20-37:2.

[353] Ex. 9, O'Connor Rebuttal at 121:16-23.

[354] Tr. Vol. IV (Jacobs) at 15:8-9.

[355] Tr. Vol. IV (Jacobs) at 15:8-19.

where changes were needed. The record evidence illustrating the extent of our choices, our thorough examination of alternatives, and our robust management processes establishes the overall prudence of our Program management.

D. LCM/EPU Split

We next turn to the issue of the correct LCM/EPU split, if any, to be used in this case. The Department's Initial Brief supports use of a 14.7/85.3 percent LCM/EPU split developed in the testimony of Dr. Jacobs, based on his opinion that if a component had anything at all to do with the uprate, 100 percent of the costs for that component would be categorized EPU, regardless of whether that piece of equipment needed to be replaced anyway.[356] The Company respectfully disagrees with this EPU-centric approach as it (i) is inconsistent with the approach to the split taken in 2008 and therefore injects hindsight into this prudence inquiry; (ii) does not reflect the actual condition of the components and the need to replace many of them for long-term plant operations, and (iii) is inconsistent with the way Dr. Jacobs allocated costs between the uprate and life extension in the Florida proceedings he participated in. In this Section of our Reply Brief, we will respond to the Department's analysis of the LCM/EPU Split.

1. Framework for the LCM/EPU Split Issue

As noted in our Initial Brief, there are three relevant questions with respect to the Department's proposed LCM/EPU split:

- Is a split of costs between LCM and EPU activities even relevant to this case?

[356] Department Initial Br. at 48-61.

- If yes, what is the appropriate split for purposes of determining our prudence?

- What is the appropriate split for assessing a remedy, if imprudence is found?

We addressed these issues at length on pages 110-127 of our Initial Brief. It remains the Company's position that no LCM/EPU split is relevant because:

- The Program is overwhelmingly cost-effective as a whole;[357]

- The work done provides benefits to customers in an integrated manner, as the affected equipment operates in simultaneous support of both the continued operation and uprated condition of Monticello;[358]

- The Program was planned and implemented as an integrated project;[359]

- For purposes of assessing prudence, a split derived from final costs is precisely the kind of hindsight analysis that is inconsistent with the legal test;[360]

- The Company would have had to complete the significant majority of the work regardless of whether an EPU was undertaken;[361] and

- Even if some of the LCM or EPU work could have been delayed as Dr. Jacobs suggested – without having reviewed the age, condition, or remaining life of the equipment – delayed work would have come at a higher cost.[362]

For purposes of determining prudence, if any split is used at all, then the Commission should continue to use the 58.4/41.6 percent LCM/EPU split that was developed in good faith for purposes of the 2008 decision to proceed with the Program. This split

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[357] Ex. 309, Shaw Direct at 14:1-2.

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

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

[360] Xcel Energy Initial Br. at 111-112.

[361] Ex. 9, O'Connor Rebuttal at 87:19-21.

[362] Tr. Vol. IV (Jacobs) at 15:8-12.

is consistent with the critical timeframe identified in the Department's cost-effectiveness analysis and does not represent an after-the-fact view of final costs.

The Department acknowledges that the 58.4/41.6 LCM/EPU split was used in 2008[363] and does not challenge that this was a reasonable allocation at the time. The Department asserts that, in hindsight, the split used in 2008 is "unrealistic."[364] However, to apply the prudent investment standard appropriately, it is necessary for the Commission to apply the facts and assumptions that were reasonably made at the time.[365]

For purposes of assessing a remedy (if imprudence is found) then the Commission should again not use a split at all, recognizing the integrated nature of the initiative. If a split is desired to assess harm, then the split that correctly conveys the actual harm caused by the imprudence is one that shows what work could have been avoided had the imprudence not occurred. If work was going to be done anyway, then no damages should be assessed because the imprudence, even if found, did not cause any harm.[366]

In this instance, the 78/22 percent LCM/EPU split developed to determine the avoidable EPU costs from Mr. O'Connor's Direct Testimony should be used. Since 78 percent of the work needed to be done in any event, that should be taken into account if the ALJ or Commission decide to impose a remedy for some specified imprudence.

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[363] Ex. 307, Jacobs Surrebuttal at 16:5-6.

[364] Department Initial Br. at 97.

[365] *Gulf States Utils. Co.*, 578 So. 2d at 85 (citing *Metzenbaum*, Opinion No. 25, 4 FERC 61,277, 26 P.U.R.4th 144).

[366] *See Potomac Elec. Power Co.*, 661 A.2d at 141-42; *State ex. rel. Associated Natural Gas Co.*, 954 S.W.2d at 530 (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers); *New England Power Co.*, 31 FERC 61,047 at 61,089 n.38 (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers)).

The Department continues to suggest that Dr. Jacobs' EPU-centric 14.7/85.3 percent LCM/EPU split is both relevant and accurate to both the prudence and remedy questions. However, the Department's Initial Brief focuses almost exclusively on Dr. Jacobs' own pre-filed testimony and evidentiary hearing opening statement. They do not discuss the fundamental problems with Dr. Jacobs' analysis as evidenced by other, objective documentation in the record; by the detailed testimony of Company witnesses regarding the need for specific work; and by cross-examination of Dr. Jacobs at the evidentiary hearing.

Overall, Dr. Jacobs' LCM/EPU split is not only irrelevant as an after-the-fact division of Program costs to determine cost-effectiveness, but is not based on the full body of important evidence in the record. We also addressed the serious evidentiary concerns with Dr. Jacobs' LCM/EPU split in our Initial Brief, where we:

- Provided parallel discussion from other jurisdictions rejecting the kind of breakeven analysis Dr. Jacobs and Mr. Shaw conducted here, as it constitutes a hindsight analysis of cost-effectiveness;[367]
- Explained why utilizing a single document from 2008 ("NRC Enclosure 8")[368] to split final Program costs as of 2013 into LCM and EPU categories was not appropriate;[369]
- Identified the specific areas where Dr. Jacobs inconsistently departed from the lone document on which he relied;[370]
- Illustrated that a small incremental increase in the size of a modification to accommodate EPU conditions did not warrant attributing 100 percent of modification costs to the EPU, especially since Dr. Jacobs'

[367] Xcel Energy Initial Br. at 111-112, 118-119.

[368] Ex. 305, Jacobs Direct at Attachment WRJ-2 at 3.

[369] Xcel Energy Initial Br. at 112-114, 115-117.

[370] Xcel Energy Initial Br. at 121-123; 124; *see* Tr. Vol. III (Jacobs) at 124:8-14 (condensate demineralizer control system had to be changed regardless of EPU)).

analysis ignored the underlying age and condition of the overall equipment;[371]

- Described in detail the drivers of cost increases that supported a greater attribution of costs to LCM purposes;[372]

- Explained that the 58.4/41.6 percent LCM/EPU split used and accepted in the Certificate of Need is consistent with the prudence standard and does not inject hindsight into the analysis;

- Illustrated that if any present engineering analysis of a split between LCM and EPU should be utilized in this proceeding, the Company's analysis is consistent with the facts and has more complete and accurate support in the record.[373]

With this framework from the Company's Initial Brief, we turn to the Department's specific arguments continuing to support Dr. Jacobs' LCM/EPU split.

2. LCM was Focus of the Initiative

Dr. Jacobs assumes that the Program was driven by the desire to complete the EPU. From that mistaken assumption, he concludes (i) that the work we did was wholly attributable to the EPU, and (ii) if we had chosen not to do the EPU we could have avoided a significant amount of the work. The record facts, however, show that Dr. Jacobs' assumption and conclusion are backwards. The contemporaneous evidence provided by the Company shows that the purpose of the EPU was "integration with Life Cycle Management projects for the Monticello Nuclear Generating Plant."[374] Most of the items under discussion in this proceeding were identified in Company

[371] Xcel Energy Initial Br. at 114-115.

[372] Xcel Energy Initial Br. at 119-128.

[373] Xcel Energy Initial Br. at 119-128.

[374] Ex. 16, O'Connor Surrebuttal at Schedule 6 at 4.

documents from 2003 or before as needed for "increased plant reliability and safety for the extended period of time of operation" of Monticello.[375]

Dr. Jacobs does not dispute that documents from the 2001-2006 timeframe all point to the need to replace these components regardless of the uprate.[376] Mr. O'Connor makes it clear that the LCM (and not the EPU) drove our decisions:

> Additionally, many of our contemporaneous documents from the time the Program was initiated support our decision to combine the initiatives as an integrated Program. I have attached three of these documents to my Surrebuttal Testimony as Exhibit ___ (TJO-3), Schedules 3, 4, and 5. Exhibit ___ (TJO-3), Schedule 3 is a spreadsheet that identifies our 10-year Capital Projects as of November 11, 2005. As shown on the page marked NSP 0000612, we included a category for LCM, including the generator/exciter rewind, replacing the 13A/B, 14A/B, and 15A/B feedwater heaters, replacing the main transformer, and replacing 4 kV breakers. Exhibit ___ (TJO-3), Schedule 4 is a spreadsheet of our 10-year Long Range Plan as of June 26, 2006. This document coincides with the Company's initial evaluation combining the LCM and EPU initiatives. As shown on the page marked NSP 0000836, we identified multiple projects that would be necessary for the EPU, separate from the LCM projects on the page marked NSP 0000833 of this Schedule. Exhibit ___ (TJO-3), Schedule 5 is a spreadsheet of our 10-year Long Range Plan as of August 7, 2006. As shown on the page marked NSP 0000890, many of the projects that were under LCM in June of 2006 were moved to "Projects Included in Power Uprate Project" including the 13A/B, 14A/B, and 15A/B feedwater heaters, the main steam feedwater piping, and the main and 1AR transformers.[377]

For example, with regard to the feedwater heaters, the record is undisputed that they were a long-standing concern for the Company. By at least 2001 we had identified the need to replace the Plant's feedwater heaters if we extended the operating license.[378]

[375] Tr. Vol. III (Jacobs) at 132:20-140:16; Ex. 9, O'Connor Rebuttal at Schedule 32.

[376] Tr. Vol. IV (Jacobs) at 9:5-8.

[377] Ex. 16, O'Connor Surrebuttal at 24:1-20.

[378] Ex. 9, O'Connor Rebuttal at 103:17-106:9 and Schedule 32.

The six feedwater heaters we replaced needed to be replaced regardless of whether we undertook the uprate.[379] Dr. Jacobs has testified in other proceedings that items such as feedwater heaters and main transformers are "typically required to ensure reliable operations beyond the original 40 year operating life of the plant."[380]

While there is no question the work associated with replacing the feedwater heaters and associated piping and drains was an expensive task, there is also no question that the work was necessary and was going to have to occur regardless whether we proceeded with the uprate. And Dr. Jacobs agreed that it is normal to change out the feedwater heaters in support of life extension (irrespective of the uprate).[381] They had been on the long-range plan for replacement since at least 2003.[382] This contemporaneous document makes clear that "[s]ervice life of feedwater heaters requires they be replaced to support the extended period of operation. Not replacing these components could potentially lead to an extended shutdown."[383]

At the hearing, Dr. Jacobs also criticized our need to replace piping associated with the heaters and ascribed that effort to the uprate.[384] But it is beyond dispute that the piping had been identified as needing replacement in the 2003 long range plan.[385] And Dr. Jacobs admitted that contemporaneous documents showed this piping needed to be replaced in any event.[386]

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379 Ex. 9, O'Connor Rebuttal at 105:21-23.

380 Tr. Vol. IV (Jacobs) at 26:24-27:6, 30:6-10; Ex. 428, *In re Nuclear Cost Recovery Clause*, Fla. Pub. Serv. Comm'n No. 080009-EI, REVISED DIRECT TESTIMONY AND EXHIBITS OF WILLIAM R. JACOBS, JR., PH.D. at 9:14-16 (July 30, 2008).

381 Tr. Vol. IV (Jacobs) at 29:9-14.

382 Ex. 9, O'Connor Rebuttal at Schedule 34 at 14.

383 Ex. 9, O'Connor Rebuttal at Schedule 34 at 14.

384 Tr. Vol. IV (Jacobs) at 65:21-66:2.

385 Ex. 9, O'Connor Rebuttal at Schedule 34 at 15.

386 Tr. Vol. IV (Jacobs) 4:7-13, 9:17-18; 13:22-24.

A second example is the need to replace the 40- and 60-year old transformers at the Plant. The evidence provided by the Company identifies the need to replace transformers due to age-related deterioration.[387] We identified this as early as 2001 and it was on the 2003 capital projects summary.[388] Again, Dr. Jacobs agreed that replacement of main transformers would be typical equipment that would need to be replaced during the original 40 year operating life of the plant.[389]

A third example is the Company's identification in our 2001 Long Range Plan that the reactor feed pump and motors system needed to be replaced to increase plant reliability for the license extension period irrespective of the uprate.[390] Not replacing this component could potentially lead to an extended shutdown, which was an unacceptable risk if the Company was going to seek to extend the license. The decision to replace the reactor feed pumps and motors was driven by service-related degradation issues and obsolescence.

The most obvious example relates to the need to add distribution capacity to the plant irrespective of the uprate. In 2001, the Company identified 4 kV breaker replacement as a necessary modification if the license was renewed.[391] While we did not decide to upsize the new breakers to 13.8 kV until later, it was clear that additional distribution capacity was recognized as an important LCM need for Monticello. As Mr. O'Connor summarized:

> Electricity and water are the life blood of a BWR plant, such as Monticello. As a result, it is essential that Monticello have adequate electrical capacity and reliability to support Monticello's operations. . . .

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[387] Ex. 9, O'Connor Rebuttal at Schedules 33 and 34.

[388] Ex. 9, O'Connor Rebuttal at 114:9-15 and Schedule 33 at 13, Schedule 34 at 10.

[389] Tr. Vol. IV (Jacobs) at 29:9-14.

[390] Ex. 9, O'Connor Rebuttal at 109:9-15 and Schedule 33 at 13.

[391] Ex. 9, O'Connor Rebuttal at Schedule 33 at 13.

Thus, the existing 4 kV system was operating with minimal margins which increased the risk of trips or forced outages.[392]

. . . .

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

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

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

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

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

- Buses. The existing 4 kV electrical buses were very close to maximum electrical fault ratings prior to the LCM/EPU Program. Specifically, bus #11 was less than 500 interrupting amps from its maximum rating or 99 percent of its maximum rating. Operating

[392] Ex. 9, O'Connor Rebuttal at 94:6-19.

> in this condition does not allow for any recovery from ground fault related events.[393]

And Dr. Jacobs explicitly admitted that problems of this type indicated that work needed to be done to upgrade the distribution system "independent of the EPU."[394]

3. Dr. Jacobs' EPU-Centric Focus

As noted in the Company's Initial Brief,[395] there is room for debate about the precise percentage of costs that could be attributed (on a hindsight basis) to LCM and/or EPU activities under any analysis. The fundamental difference between Dr. Jacobs and the Company, however, is that the Company took an incremental cost approach that examined what work needed to be done absent the uprate and what additional or incremental costs could be avoided if the Company had not undertaken the uprate. This is consistent with internal Company documents at the time and actually represents a conservative view of the ratio of costs between the LCM and EPU aspects as suggested by the 2003 presentation included with Mr. O'Connor's Rebuttal Testimony.[396]

In contrast, Dr. Jacobs assumed that if any changes to Monticello equipment completed via the Program were needed to accommodate the EPU, all charges for that equipment were EPU-related regardless of any changes that would have been required for LCM purposes.[397] The Department refers to Dr. Jacobs' method as a "but-for" test, arguing that the work would not have been done but for the uprate.[398]

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[393] Ex. 9, O'Connor Rebuttal at 94:21-96:2.

[394] Tr. Vol. IV (Jacobs) at 35:4-7.

[395] *E.g.*, Xcel Energy Initial Br. at 125-127.

[396] Ex. 9, O'Connor Rebuttal at Schedule 4.

[397] Department Initial Br. at 48; Ex. 421, Jacobs Opening Statement at 1.

[398] *E.g.*, Department Initial Br. at 53.

Dr. Jacobs justifies this approach on three grounds, claiming that (1) "routine LCM modifications often are like-for-like replacements (using the term generally) and, thus, are typically significantly less costly than replacements with larger components";[399] (2) "LCM modifications typically are planned to be completed during normal refueling outages over many years";[400] and (3) "in EPU-related work, the modifications are not spread over many years because the plant cannot operate at its higher intended level until all the EPU-necessary work is done."[401]

The Department's characterization of this as a 'but-for' test is wrong in that it mischaracterizes the record. The record is clear that most of the equipment we replaced would have been replaced in the near term without regard to the uprate. Even Dr. Jacobs admitted that the two most expensive modifications (feedwater heaters and distribution system) needed to be upgraded without regard to the uprate. In reality, the Department's approach is "EPU-centric" in the sense that it loads costs onto the uprate without regard to the actual circumstances.

The further problem with Dr. Jacobs' overall approach is it assumes that Dr. Jacobs' generalities about "routine" or "typical" LCM work (which are in themselves unsupported by documented evidence or contemporaneous documents) apply specifically to the Monticello LCM/EPU Program. Dr. Jacobs provided no evidence that his generalities about "routine" or "typical" LCM apply are supported in the industry, let alone applicable to the complex work of replacing major systems at Monticello at the end of their 40-year operating lives.

Moreover, Dr. Jacobs' overall argument in support of his "EPU-centric" approach applies the circular reasoning that because certain work was complicated or atypical, it

399 Department Initial Br. at 54.

400 Department Initial Br. at 54.

401 Department Initial Br. at 55.

must be EPU-driven. This assumption ignores that because the EPU program coincided with the end of the Monticello's original operating life, complex work was needed for both purposes at the same time. Assuming that complicated work was driven by the EPU was simply an unfair and simplistic assumption.

a. Like-for-Like

More specifically, the evidence indicates the work to be done through the Program – regardless of whether it is characterized as LCM or EPU – was neither routine nor typical. First, Dr. Jacobs argues that his EPU-centric test is appropriate because routine, "like-for-like" LCM work is often less costly than EPU equipment replacements.[402] Even assuming for the moment that only EPUs drive equipment replacements, "like-for-like replacements can be challenging and have actually resulted in the shutdown of nuclear plants.[403] In describing two nuclear plants that have recently been shut down due to 'like-for-like' replacements that went wrong, Mr. O'Connor testified:

> Like-for-like replacements in the nuclear industry are not simple nor risk-free. We just completed the replacement of the steam generator at Prairie Island Unit 2. That project is currently the subject of the pending rate case and, as described in that proceeding, I would not say the replacement was easy, although I am gratified that Prairie Island successfully went back into service at the conclusion of the installation and is operating well. Unfortunately, not all nuclear utilities have fared as well in the installation of steam generators and I frankly think that Dr. Jacobs picked a bad example.[404]

Further, Dr. Jacobs claims he intended to talk about "like-for-like" work generally, but by his own admission this definition is inconsistent with the NRC's requirements that

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[402] Department Initial Br. at 54.

[403] Ex. 9, O'Connor Rebuttal at 119:15-18.

[404] Ex. 9, O'Connor Rebuttal at 119:4-11.

like-for-like work (a nuclear term of art)[405] is only possible when the same equipment is available from the same vendor – a rare circumstance when dealing with 40-year-old nuclear equipment.[406] As a result, there were few components of the Program that were "routine" or "like-for-like," but this was due to the age and condition of the Monticello systems and is not a basis for assuming complex work was EPU-driven.

b. Typical Replacements

Second, Dr. Jacobs claims that "LCM modifications typically are planned to be completed during normal refueling outages over many years."[407] This argument not only again assumes "typical" LCM work and planning rather than the larger and more complicated LCM work needed to keep Monticello operating over its extended life, but also ignores that the Program was in fact completed over multiple refueling outages. In addition, Dr. Jacobs offers up this statement without having analyzed the age or condition of the equipment to determine whether it was possible to delay or avoid any specific Program work absent the EPU:

> Q. And we've already established, I believe, that you didn't specifically assess whether that equipment was in sufficiently good condition to keep operating another 20 years, with or without an uprate?[408]
>
> A. That's correct.
>
> Q. And I don't see anywhere in your testimony where you specifically address how long the plant could have operated absent an uprate using the existing equipment.

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405 Tr. Vol. IV (Jacobs) at 52:12-16; Ex. 429, NRC – Licensee Commercial-Grade Procurement and Dedication Programs (Generic Letter 91-05) (providing NRC definition of "like-for-like"); Ex. 420, NRC Inspection Manual, Inspection Procedure 43004, Program Applicability: 2504, 2507, 2700 (providing NRC definition of "like-for-like); Ex. 431, NRC Inspection Manual, Inspection Procedure 43004, Program Applicability: 2504, 2507, 2515C (providing NRC definition of "like-for-like").

406 Ex. 9, O'Connor Rebuttal at 117:5-7.

407 Department Initial Br. at 54.

408 Tr. Vol. IV (Jacobs) at 36:11-14.

A. I did not address that topic, no.

. . . .

Q. And you have not done an independent assessment of how long the plant could have continued operating at pre-EPU levels, we've already talked about that.

A. I stated it could have continued operating. It was operating before, it got the license, and it could have continued afterwards.

Q. One year, ten years, five years? No opinion, right?

A. No opinion.[409]

In contrast, Company witness Mr. O'Connor offered detailed Direct and Rebuttal testimony explaining why much of the Program work was driven by complex life cycle management needs of the plant.[410] These detailed discussions should have more bearing on an LCM/EPU split than Dr. Jacobs' assumption that the EPU was the primary focus of the effort.

c. Spreading Work

Third, Dr. Jacobs argues that his test is appropriate because "in EPU-related work, the modifications are not spread over many years because the plant cannot operate at its higher intended level until all the EPU-necessary work is done."[411] But the same is true of LCM work that is needed to keep the plant operating. Dr. Jacobs asserted that Monticello could have continued to operate at existing generation levels without the Program, but he testified that he did not assess what work could be delayed[412] or how

[409] Tr. Vol. IV (Jacobs) at 36:6-37:19.

[410] Ex. 3, O'Connor Direct at 93:1-136:11 and Schedules 29, 30; Ex. 9, O'Connor Rebuttal at 81:1-123:18 and Schedule 32.

[411] Department Initial Br. at 55.

[412] Tr. Vol. IV (Jacobs) at 16:1-6; 34:6-16; Ex. 9, O'Connor Rebuttal at Schedule 39 (Dr. Jacobs' response to Company IR No. 17).

long the work could be delayed. He further did not know what NRC requirements had to be met regardless of the EPU:

> Q. And you also don't assess whether the NRC would have allowed the plant to continue to operate under its existing conditions for any length of time?
>
> A. I don't state that, no.[413]

Finally, Dr. Jacobs agreed that Program work may have been even more expensive if delayed.[414]

In short, Dr. Jacobs' "EPU-centric" test is not premised on his analysis of the specific needs at Monticello for any of the Program modifications, but rather on his assumption that work must be EPU-driven if it is needed in the short-term or is complex. Dr. Jacobs has offered no analysis, industry data, or information to show that this assumption is objectively correct, let alone correct when applied specifically to Monticello's needs. Accordingly, his LCM/EPU split is premised on a faulty "EPU-centric" test that undermines the remainder of his analysis.

4. Dr. Jacobs' Reliance on Enclosure 8

After explaining Dr. Jacobs' approach, the Department contends that he "used several methods of identifying EPU-only projects, but relied to a considerable extent on Xcel's 2008 sworn letter to the NRC…," to develop his LCM/EPU split. However, the record and the limited citations in the Department's Initial Brief demonstrate that the 2008 NRC Enclosure 8, as reviewed in the context of his "EPU-centric" test, was virtually the exclusive basis for Dr. Jacobs' conclusions.[415] The Company respectfully

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413 Tr. Vol. IV (Jacobs) at 38:8-11.

414 Tr. Vol. IV (Jacobs) at 15:1-15:19.

415 Department Initial Br. at 48 (citing Ex. 305, Jacobs Direct at Attachment WRJ-2). The exception, of course, was Dr. Jacobs' attribution of 100 percent of the costs of the 13.8 kV system to the EPU even though Enclosure 8 said nothing about the EPU with respect to the 13.8 kV system.

disagrees with Dr. Jacobs' singular reliance on this document as described in our Initial Brief at pages 112-116, noting that Dr. Jacobs' use is incorrect and overly narrow.

The Department specifically suggests that Dr. Jacobs' use of this document to the exclusion of all others is appropriate because it would not be necessary for the Company to address work the NRC previously approved for life extension in a subsequent letter regarding an uprate, and because this letter reflects what the Company knew or should have known in 2008.[416] But this approach misunderstands NRC requirements for an uprate application. The cover letter accompanying the NRC Enclosure 8 notes that approval for an uprate is requested "pursuant to 10 CFR 50.90."[417] 10 CFR 50.90 specifies that:

> Whenever a holder of a license . . . desires to amend the license or permit, application for an amendment must be filed with the Commission, as specified in §§ 50.4 or 52.3 of this chapter, as applicable, fully describing the changes desired, and following as far as applicable, the form prescribed for original applications.[418]

Moreover, the Company states in the NRC letter that:[419]

> **Enclosure 8 includes a list of modifications planned for EPU implementation. The modifications listed in Enclosure 8 are planned actions which do not constitute regulatory commitments by NSPM. Modifications listed in Enclosure 8 are beina implemented in accordance with the requirements of 10 CFR 50.59.**

10 CFR 50.59(a)(1) in turn describes the "changes" that must be identified in an application under 10 CFR 50.90:

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416 Department Initial Br. at 51-52.

417 Ex. 305, Jacobs Direct at Attachment WRJ-2 at 1.

418 10 CFR 50.90 (2014).

419 Ex. 305, Jacobs Direct at Attachment WRJ-2 at 3. Although the Company does not dispute that this document was provided under oath and represents the information known at the time, this language made it clear that Enclosure 8 was never intended to be a definitive list of work to be done in support of the EPU, let alone work to be done at the plant overall.

> Change means a modification or addition to, or removal from, the facility or procedures that affects a design function, method of performing or controlling the function, or an evaluation that demonstrates that intended functions will be accomplished.[420]

Tying the Company's 2008 NRC letter together with the governing federal regulations clarifies both the fallacy of Dr. Jacobs' reliance on this document and the proper purpose of Enclosure 8: As required by federal regulation, Enclosure 8 identified any instance in which a change to equipment could be needed to implement the EPU – not any instance in which the entire need for the equipment work was driven by the EPU.[421] The 2008 letter simply built upon the prior license extension approval, identifying incremental issues related to the EPU.

In addition to misunderstanding the NRC requirements for the uprate application, Dr. Jacobs' manner of applying the 2008 NRC letter to final Program costs assumes either that the Company knew the final cost would be $665 million and drafted the Enclosure 8 in accordance with that knowledge, or that the increases in costs the Company experienced after the 2008 NRC document were driven solely by EPU considerations Dr. Jacobs' manner of using this document further assumes that any time the Company mentioned the EPU, the entire equipment was replaced solely because of the EPU. None of these assumptions comports with the facts.

a. Dr. Jacobs' Erroneous Analysis

First, it is important to be clear what the NRC Enclosure 8 that Dr. Jacobs relies upon actually says, as this document was not intended to present a list of modifications that were solely needed for the EPU.[422] Rather, the introduction to Enclosure 8 states that the tables in the Enclosure "also include modifications that are not required for EPU

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[420] 10 CFR 50.59(a)(1).

[421] Ex. 305, Jacobs Direct at Attachment WRJ-2 at 3.

[422] Ex. 9, O'Connor Rebuttal at 87:5-22.

but have been approved as part of the life cycle management (LCM) program. These LCM modifications are coordinated with the EPU project and will include design criteria that incorporate EPU conditions to maintain or improve performance of the respective systems."[423] Moreover, for many of the modifications that reference a need for different sizing to accommodate EPU conditions, the letter does not identify the incremental cost of sizing certain components for EPU conditions as opposed to the complete need to overhaul or replace certain equipment.[424]

In addition, many items Dr. Jacobs assigned exclusively to the EPU were identified in other key, contemporaneous documents as needed for LCM purposes regardless of the EPU. As Dr. Jacobs acknowledged on cross-examination (but not in his pre-filed testimony),[425] the following work was all identified in the ISFSI Certificate of Need as representative work needed for LCM – regardless of the EPU – and was completed as part of the LCM/EPU Program:

- Steam Dryer;
- Electrical breaker replacement;
- Cable replacement;
- Replacement of main steam and feedwater piping;
- Replacement of feedwater heaters; and
- Replacement of static exciters.[426]

Dr. Jacobs acknowledged that these modifications, though in many respects sized to support the EPU, "were also needed regardless of the EPU for life extension."[427] Yet

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[423] Ex. 305, Jacobs Direct at Attachment WRJ-2 at 6.

[424] Ex. 305, Jacobs Direct at Attachment WRJ-2 at 6; Ex. 9, O'Connor Rebuttal at 87:10-21.

[425] Tr. Vol. IV (Jacobs) at 11:11-23.

[426] Tr. Vol. IV (Jacobs) at 13:8- 14:11.

Dr. Jacobs assigned 100 percent of the costs of all of this work (with the exception of the steam dryer) to the EPU. As a result, Dr. Jacobs' LCM/EPU split is not supported by substantial evidence in the record.

b. Condensate Demineralizer Example

Dr. Jacobs' treatment of the condensate demineralizer exemplifies the flaws in his singular reliance on the NRC letter and his failure to contemplate the specific language of the Letter. With respect to Condensate Demineralizer Replacement the NRC Letter states:

Condensate Demineralizer Replacement	Replace the existing condensate demineralizer vessels with new vessels to accommodate increased flow under EPU conditions. Replace the existing control panel with a new digital control panel.

[428]

Notably, this document speaks only to condensate demineralizer vessels with respect to EPU needs. It is correct that the Company used larger vessels and piping to accommodate the EPU,[429] but attributing 100 percent of all condensate demineralizer replacement costs to the EPU ignores that (1) the overall system was deteriorated and obsolete, including vessels, filters, and system wiring; [430] (2) by 2010, vessel and filter elements needed to be recharged every six months;[431] (3) the 1960s-era analog control system was obsolete, such that it would have been imprudent to replace it with digital controls regardless of the EPU;[432] (4) the NRC letter identified the analog control

[427] Tr. Vol. IV (Jacobs) at 14:9-10.

[428] Ex. 305, Jacobs Direct at Attachment WRJ-2 at 12.

[429] Ex. 9, O'Connor Rebuttal at 107:2-5.

[430] Ex. 9, O'Connor Rebuttal at 107:20-22; 108:11-13.

[431] Ex. 9, O'Connor Rebuttal at 107:21-22.

[432] Ex. 9, O'Connor Rebuttal at 107:23-24, 108:3-4.

system replacement independent of the EPU;[433] and (5) by 2000 – before an EPU was planned – the Company had already recognized replacement of the pneumatic flow controllers and stepping switch controller was necessary.[434] And Dr. Jacobs acknowledged that he did not assess the age or need of the equipment.[435] Perhaps most importantly, his assignment of 100 percent of total condensate demineralizer replacement costs to EPU ignores that the lone document he replied upon speaks only to condensate demineralizer vessels with respect to the EPU and specifically separates analog panel replacement from EPU considerations. As a result, the Company's approach of attributing the larger portion of condensate demineralizer costs to LCM activities[436] comports with the facts, while Dr. Jacobs' 100 percent EPU attribution does not.

c. Distribution System Example

The similar problems with Dr. Jacobs' approach are illustrated by his treatment of the 13.8 kV system. Here, Dr. Jacobs testified that there were three reasons he decided the 13.8 kV system was exclusively EPU-related: (1) Enclosure 8 to the NRC Letter; (2) Dr. Jacobs' experience with EPUs prior to speaking with Mr. O'Connor or visiting the Plant; and (3) a conversation with Mr. O'Connor during Dr. Jacobs' visit to Monticello.[437]

As to his first basis, Dr. Jacobs admitted that the NRC Letter expressly states that the 13.8 system is "an LCM modification to increase margin in the on site [sic]

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[433] Tr. Vol. III (Jacobs) at 124:11-14 ("in the second part, relating to the [condensate demineralizer] control panel, it does not reference the EPU; correct? A. That's correct.").

[434] Ex. 9, O'Connor Rebuttal at Schedule 32.

[435] Tr. Vol. IV (Jacobs) at 36:11-15.

[436] Ex. 9, O'Connor Rebuttal at Schedule 30 at 10.

[437] Tr. Vol. IV (Jacobs) at 16:7-17:3.

distribution system."[438] He did not consider earlier and contemporaneous documentation illustrating the need to replace the 4kV breakers regardless of the EPU.[439]

As to his second basis, Dr. Jacobs has no experience with any facility upgrading a distribution system for *EPU* purposes, and did not know whether other nuclear facilities – including those he had worked on – already had a 13.8 kV distribution system to support ongoing plant systems.[440] As a result, his experience says nothing about distribution system needs for LCM.

Third, Dr. Jacobs relies heavily on a question and answer with Mr. O'Connor that was never recorded and which Dr. Jacobs declined to ask in writing so all Parties to this proceeding could evaluate it on its face.[441] In any event, Mr. O'Connor did not say the 13.8 kV system was needed solely for EPU purposes; rather, he said that it was necessary to add distribution system capacity regardless of the EPU.[442] And in testimony Mr. O'Connor explained:

> During our interview Dr. Jacobs asked me a question similar to the following: "Was it necessary to upgrade to 13.8 kV voltage if you had not done the uprate?" My answer was that a higher voltage may not be required without the uprate. This was an acknowledgment that the decision in 2007 to install 13.8 kV system was precipitated by the need to provide additional electricity to run the larger pumps and motors that were being installed for the uprate. However, this does not negate the longer term need that Monticello had for additional distribution capacity and to replace the aging distribution equipment. It is possible that,

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438 Ex. 305, Jacobs Direct at Attachment WRJ-2 at 13.

439 Ex. 9, O'Connor Rebuttal at Schedule 33 at 13; Ex. 10, O'Connor Rebuttal at Schedule 32 at 28-41 (Non-Public).

440 Tr. Vol. IV (Jacobs) at 18:13-20:11. Tellingly, Dr. Jacobs wasn't aware that the Palo Verde nuclear facility where he worked has a 13.8 kV system, or that Monticello's sister plant in Spain had difficulties taking a piecemeal approach to upgrading their 4 kV system.

441 Tr. Vol. IV (Jacobs) at 20:18-23:17.

442 Tr. Vol. IV (Jacobs) at 23:6-17.

> absent the uprate, we may have decided to add distribution capacity at a different voltage. Strictly speaking, 13.8 kV was not required absent the uprate but additional distribution capacity whether at 4 kV, 6.9 kV, or 13.8 kV was needed without the uprate. But Dr. Jacobs, for some reason, disregards the contemporaneous information provided to him regarding the need for enhanced distribution margin as well as the fact that space limitations in the existing power block would have required locating the additional bus in the same location. These same space constraints would drive the requirement to run many miles of cable and raceway to accommodate the new system. Thus, the cost of new distribution capacity would not have been avoidable absent the EPU.[443]

Importantly, unlike Mr. O'Connor,[444] Dr. Jacobs never evaluated that need nor compared costs of replacing the 4 kV system with a 13.8 kV system vs. a system of some other voltage:

> Q. And your testimony does not discuss any Monticello site system specific facts that would show additional on-site electrical distribution was not necessary to accommodate the life extension of the plant?
>
> A. That's correct.[445]
>
> . . . .
>
> Q. [T]he voltage may have been somewhat different, but some distribution system had to be put in regardless of the EPU, correct?
>
> A. I believe at some point, yes.
>
> Q. And you didn't do an independent assessment of that need, as we've already discussed?
>
> A. I did not.
>
> Q. And would it also be fair to say that neither your direct nor rebuttal testimony compared that cost of a new 13.8 kV system with the cost of an upgrade of the 4 kV system?

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443 Ex. 9, O'Connor Rebuttal at 89:2-20.

444 Ex. 9, O'Connor Rebuttal at 99:9-21.

445 Tr. Vol. IV (Jacobs) at 20:12-17.

A. I did not.[446]

In fact, Dr. Jacobs acknowledged that under voltage alarms occurring at the plant prior to the EPU indicated the need for distribution work absent the EPU:

> Q. Were you aware that the plant was receiving 4 kV undervoltage alarms when starting large motors even before EPU work was being done?
>
> A. I am aware of that, yes. I'm not sure at what point in time I became aware of that.
>
> Q. And do you have any opinion about whether that indicated the need for distribution system work independent of the EPU?
>
> A. I believe it would, yes.[447]

Consequently, the record establishes that Dr. Jacobs' bases for assigning costs to the EPU were inconsistent with the specific facts.

5. Inconsistent Positions

The sole purpose of Dr. Jacobs' LCM/EPU split in this proceeding is to provide an input to Mr. Shaw's cost-effectiveness/breakeven analysis,[448] which is utilized to identify a disallowance even though the Department has made no findings or conclusions that specific imprudence occurred. However, even Mr. Shaw acknowledges that the EPU is cost-effective under his analysis if no more than 72 percent of total Program costs are attributed to the EPU[449] and would certainly be cost effective using the 58.4/41.6 percent split used in the Certificate of Need.[450]

[446] Tr. Vol. IV (Jacobs) at 23:14-25.

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

[448] Tr. Vol. IV (Jacobs) at 14:7-8.

[449] Ex. 309, Shaw Direct at 31 at Table 18 and 31:4-7.

[450] Ex. 309, Shaw Direct at 27:1 at Table 13.

In addition, as we describe on pages 117-19 of our Initial Brief, the bright-line methodology employed by Dr. Jacobs is fundamentally contradicted by the approach he employed in his Florida testimony.[451] In Florida, he employed the same type of breakeven analysis used by Department witness Mr. Shaw in this proceeding, but developed a split between LCM and EPU costs that supports the Company's approach here and is opposite Dr. Jacobs' own approach in this case. Dr. Jacobs attributed the incremental cost of the increased size of the components to the EPU.[452] In this way, Dr. Jacobs' approach was opposite his approach in this proceeding, where he has attributed all costs to the EPU so long as he believed any increment of the overall cost was attributable to the Monticello uprate:[453] In Florida Dr. Jacobs had an incentive to minimize costs attributed to the EPU to minimize the utilities' cost recovery. In contrast, he appears to have maximized costs attributable to the EPU to support a disallowance utilizing the Department's breakeven analysis.

6. Other Splits

The Department claims that the Company has not shown that its "avoidable EPU" analysis, which attributes 78 percent of Program costs to the LCM, was reasonable because the Company's approach "assumes, essentially, that all costs are LCM costs until proven otherwise" and because the Company did not estimate the LCM-only costs of the Program.[454] The Company frankly does not understand this criticism. Schedule 31 to Mr. O'Connor's Rebuttal Testimony provides a detailed analysis of the LCM and EPU needs and cost drivers for each individual modification. It would be correct to say that the Company attributed costs to LCM if such costs would have

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451 Florida's Office of Public Counsel is similar to Minnesota's Office of the Attorney General.

452 Ex. 428, *In re Nuclear Cost Recovery Clause*, Fla. Pub. Serv. Comm'n No. 080009-EI, REVISED DIRECT TESTIMONY AND EXHIBITS OF WILLIAM R. JACOBS, JR., PH.D. at 9-10 (July 30, 2008).

453 Ex. 305, Jacobs Direct at 7:9-11 ("My analysis identifies costs specifically needed to support the EPU project."); Tr. Vol. III (Jacobs) at 115:15-116:13 ("irrespective of other needs, without these projects, the EPU could not proceed; and therefore, I consider them to be EPU projects.").

454 Department Initial Br. at 60 (citing Ex. 307, Jacobs Surrebuttal at 12-13); Department Initial Br. at 61.

been needed absent the EPU, as this approach is consistent with the primary need to keep Monticello's 600 MW operating with or without the additional 71 MW.[455]

Further, in contrast to Dr. Jacobs' approach, the Company's analysis of the avoidable EPU is based on the sum of record evidence about the condition of our equipment and the engineering assessment of the costs attributable to each aspect. The Company took a hard look at Plant equipment, which was built with the expectation it would only be used for the duration of a 40-year operating license, and estimated (to the extent possible, after the fact) what work had to be done regardless of the EPU and what work could have been avoided if an EPU was not completed.[456]

This is not a precise process regardless of whether undertaken by the Department or the Company, as it involves engineering judgment.[457] The Company further does not disagree with Dr. Jacobs' statement that "Estimating the LCM-only costs for each project would be a challenging task."[458] Indeed, the Company found it to be a challenging, time-consuming task given the complexity of the Program and the evolving changes that drove cost increases. But based on the totality of the evidence in the record, the Company submits that any LCM/EPU split that attributes a greater portion of costs to the EPU than to LCM needs is not consistent with the record.

Notably, if the Commission modifies Dr. Jacobs' analysis only slightly to more accurately reflect that at least 50 percent of the 13.8 kV system and 50 percent of the condensate demineralizer system should be attributed to LCM needs, the Program

455 Conversely, the EPU could not have functioned if the Plant ceased to operate.

456 Ex. 3, O'Connor Direct at 145:3-147:4 and Schedules 29-31; Ex. 9, O'Connor Rebuttal at 81:6-84:11 and Schedules 30-31.

457 Tr. Vol. III (Jacobs) at 98:16-99:7.

458 Department Initial Br. at 61.

meets the Department's cost-effectiveness test.[459] It is clear that the Program becomes even more cost effective if any portion of the feedwater heaters,[460] replacement of feedwater pumps and motors,[461] and main power transformers[462] are also appropriately attributed to the EPU. Even if one were to assume that the high-pressure turbine, the reactor feed pumps and motors and condensate pumps and motors are attributable to EPU[463] it becomes about a 60/40 LCM/EPU split and would still show cost effectiveness under the Department's proposed remedy.[464]

The Department also suggests that the 51.4/41.6 percent LCM/EPU split used in the 2008 Monticello Certificate of Need is not reasonable to address cost-effectiveness because it was applied to a lower initial cost estimate (as compared to final Program costs) and does not take into account the cost increases that followed.[465] However, this 2008 split is the only reasonable split to use for assessing prudence in this proceeding *precisely because* it does not inject further hindsight into the cost-effectiveness test. Dr. Jacobs' approach of applying a 2008 document to final Program costs assumes not only that the Company knew the final costs in 2008, but also that Dr. Jacobs' reading of the reasons these modifications were undertaken in

[459] At total Program costs of approximately $665 million, 72 percent of total costs equates to $478.8 million. Dr. Jacobs attributes $569.5 million of Program costs – or 85.7 percent – to the EPU, including 100 percent of 13.8 kV system costs ($119.5 million) and 100 percent of condensate demineralizer system costs ($79.8 million). Ex. 305, Jacobs Direct at Attachment WRJ-3. If even half of the 13.8 kV system costs ($59.75 million), and half of condensate demineralizer costs ($39.9 million) are more appropriately attributed to LCM activities under Dr. Jacobs' analysis, total costs attributed to the EPU would be $469.85 million or approximately 70.6 percent. Thus, the EPU would be cost-effective even under the Department's analysis.

[460] Total cost of $24.8 million. Ex. 305, Jacobs Direct at Attachment WRJ-3.

[461] Total cost of $92.2 million. Ex. 305, Jacobs Direct at Attachment WRJ-3.

[462] Total cost of $26.5 million. Ex. 305, Jacobs Direct at Attachment WRJ-3.

[463] *See* Xcel Energy Initial Br. at 125-28 where the Company acknowledges that the categorization of these modifications are arguably a closer question than the others.

[464] This calculation is derived by taking the Company's avoidable EPU split (78/22 percent) of $519 million LCM/$146 million EPU and moving the costs allocated to LCM for the HP Turbine, Condensate Pumps and Motors and Reactor Feed Pump modifications to the EPU column. See Ex. 9, O'Connor Rebuttal at Schedule 31 at 3. This effectively transfers about $120.5 million from LCM to EPU leaving $398 (60 percent) in LCM and $266 (40 percent) in EPU.

[465] Department Initial Br. at 60.

2008 were also the reasons costs increased. Dr. Jacobs' approach therefore ignores all of the issues discovered after 2008 that drove cost increases.

Overall, as noted in our Initial Brief the Company does not support applying an LCM/EPU split to the final costs incurred for the Program. If a split is applied, for the determination of our initial decisional prudence, the 58.4/41.6 percent LCM/EPU split used in the 2008 EPU Certificate of Need is the only split that can be supported on this record consistent with applicable legal precedent. And if management imprudence is found, the Company's avoidable EPU (78/22 percent) split should be used because that is the best indicator of any harm to ratepayers.

E. Unrelated Performance Criticisms

The Department's Initial Brief also criticizes the Company's overall nuclear operations and the Company's performance generally, focusing on three areas.[466] They are:

- Regulatory Communications
- Program Accounting
- Human Performance and other Criticisms of the Plant in general

However, the Department does not tie those generalized criticisms to any costs incurred in connection with the LCM/EPU Program. Unrelated criticisms, whether justified in some other context, do not establish imprudence in this case and do not support a remedy in connection with the Program. We discussed all of these issues on pages 131-137 of our Initial Brief and will not repeat them here. This Reply focuses on the specific concerns raised by the Department's Initial Brief.

[466] Department Initial Br. at 74-84.

1. Regulatory Communications

The Department suggests that the Company provided "inadequate ... communications of mounting costs – to the extent Xcel wished assurance of future full recovery of costs."[467] The Department also argues that "at least for rate recovery purposes ... it is irrelevant whether Xcel fully informed the Commission of Monticello's soaring costs and expected cost overruns."[468] We interpret the Department as pointing out that even good regulatory communications do not guarantee cost recovery.

We agree and have never suggested that the Commission should allow cost recovery solely because we provided updates of Program cost increases over time. That determination will be made in this prudence investigation based on this record. Nevertheless, we have illustrated that our prior regulatory communications regarding Program cost increases were reasonable in response to criticisms in the Department's testimony suggesting our communications were deficient – not that our prior communications predetermined cost recovery in this proceeding.

Any criticisms that the Company should have provided more detailed regulatory communications regarding costs are not well-founded as described on pages 100-102 of our Initial Brief. In particular, since 2010 – the year *before* Program costs began to materially increase – the Company has provided regular updates in our rate cases, and has expected since 2011 that final cost recovery would be determined in this prudence investigation. Juxtaposing the Company's decisions and communications regarding Program costs with the cost increases depicted in the Chart at page 6-7 of Dr. Jacobs' Direct Testimony,[469] it is clear that the Company kept the Commission informed of changes in cost estimates:

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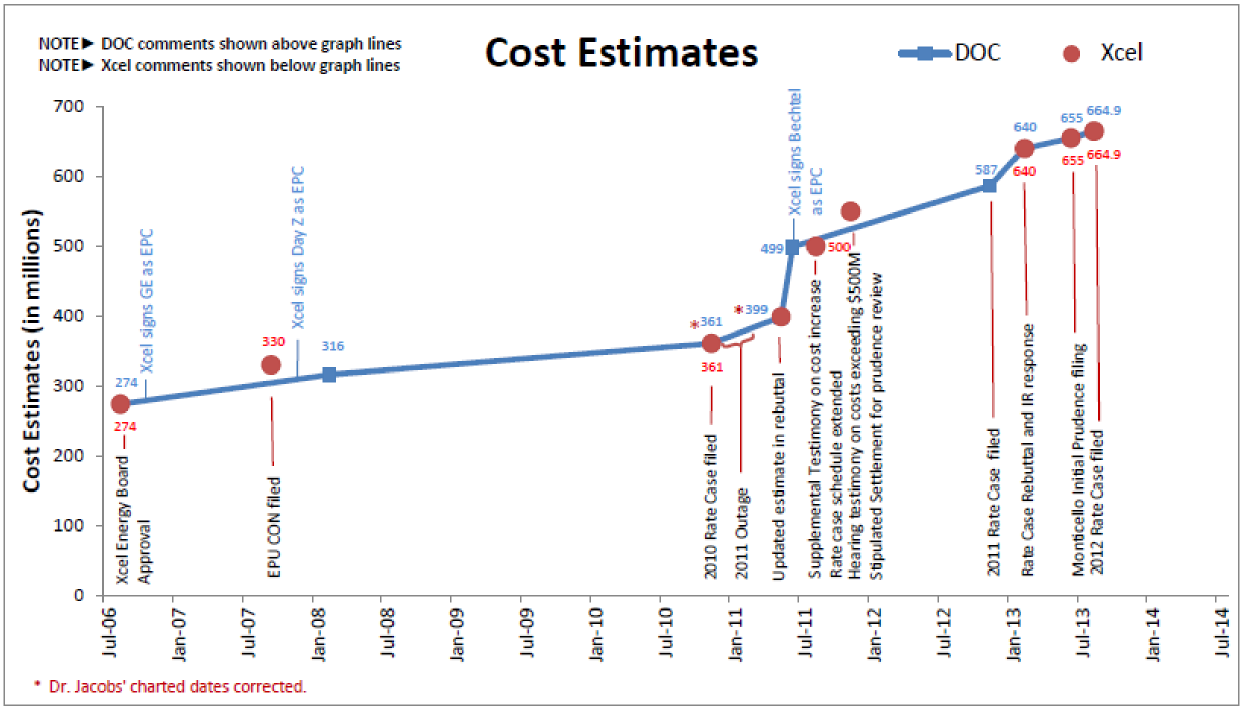
[467] Department Initial Br. at 82.

[468] Department Initial Br. at 82.

[469] Ex. 305, Jacobs Direct at 6-7.



The Commission recognized the cost increases and the need for this prudence proceeding.[470] Specifically, the Commission's Order in the 2010 rate case noted:

> First, as to reasonableness, the [Monticello project] has already been approved in a certificate of need proceeding, a baseline indication of prudence. And the project's costs – while not yet exhaustively reviewed and apparently exceeding estimates – will be tracked for refund of any portion found to have been imprudently incurred. The project itself, then, falls squarely within rate-recoverable parameters, and cost recovery will come with an unusual assurance of accuracy.[471]

[470] *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 13 (May 14, 2012).

[471] *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, at 13 (May 14, 2012) (footnotes omitted).

The Commission issued this Order after supplemental testimony, a reopening of the evidentiary hearing and the stipulation, establishing that costs had increased to at least the $550-600 million level (before AFUDC).[472]

With respect to the Department's comparison to the Company's Notice of Changed Circumstances for the Prairie Island EPU,[473] there are several significant differences between the two. First, the Prairie Island effort came after the Monticello Program was well advanced, giving us a better understanding of the cost drivers we would face. Second, by that time the Great Recession and the advent of fracking had changed the energy landscape. Third, unlike Prairie Island, with Monticello we had no reasonable opportunity or reason to stop based on our continuing analyses.[474]

Finally, the Company recognizes the importance of good communication with our regulators and regrets if the Department was dissatisfied with those communications here. Although we believe our communications were reasonable, we do not suggest they assured cost recovery, which will be decided on the record in this proceeding.

2. Accounting v. Engineering LCM/EPU Split

The Department also asserts that the Company should have accounted for the LCM and EPU initiative separately, based primarily on the following four factors: (i) two Certificates of Need suggesting separate "projects;" (ii) if Xcel Energy had accounted for them separately the Department would have been able to determine that the EPU was not cost-effective sooner; (iii) separate modeling suggests we should have

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[472] *See* Xcel Energy Initial Br. at 101-102; *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 2 (May 14, 2012). ("The ALJ held evidentiary hearings in Saint Paul on June 1-8, 2011, and reconvened evidentiary hearings on November 4, 2011 for the limited purpose of considering the Supplemental Testimony of Dennis Koehl and Richard Ostberg on the life cycle management and extended power uprate project at the Company's Monticello Nuclear Power Plant.")).

[473] Department Initial Br. at 83.

[474] Ex. 2, Alders Direct at 58-59.

accounted for costs separately during construction; and (iv) the Company has accounted for costs of other projects differently and could have done so here.[475]

a. Did Not Increase Capital Costs

First, the Department suggests that our choice of accounting treatment contributed to cost increases of the Program.[476] But the testimony quoted by the Department does not support that proposition. Rather, that testimony states that (i) separate cost tracking would increase transparency;[477] (ii) integrated cost tracking made this investigation more difficult;[478] (iii) accounting for the modifications as an integrated initiative was misplaced;[479] and (iv) the Company's internal governance structure does not bind the Commission.[480] The Company agrees with some but not all of these propositions.

As a preliminary matter, we note that none of these criticisms impacted the capital costs of the Program itself. While we appreciate the difficulty of the Department's investigation, we believe this is due to the complexities inherent in a large-scale nuclear project. Our accounting did not increase capital costs for the overall construction project. And while we respect the Department's admonition[481] that if we expect to recover money from ratepayers we need to provide transparent and accurate accounting, we do not believe their criticism in this case about conducting an ongoing LCM/EPU split analysis supports a disallowance for costs from the Program. The Commission simply has not instituted such a requirement before now. To the extent

475 Department Initial Br. at 74-80.

476 Department Initial Br. at 9 and 9 n.21 (Crisp Testimony).

477 Department Initial Br. at 31 (Crisp Testimony), and 75 (Campbell Testimony).

478 Department Initial Br. at 76 (Campbell Testimony).

479 Department Initial Br. at 79 (Campbell Testimony).

480 Department Initial Br. at 80 (Campbell Testimony).

481 Department Initial Br. at 77 (Campbell Testimony).

the Commission prefers different accounting methods going forward, we believe it would be more appropriate to address those issues outside of this proceeding.

b. Followed Commission Requirements

Most importantly, the record establishes that the Company's accounting procedures follow the FERC Uniform System of Accounts, as described on pages 134-35 of our Initial Brief. This is the manner of accounting adopted by this Commission. And the Department confirmed that it verified our costs through review of the accounting records.[482]

In addition, it was entirely reasonable for the Company to treat the LCM/EPU Program as an integrated initiative. Both purposes impacted many of the same pieces of equipment. It would have been highly inefficient to implement the two aspects separately and the FERC uniform system of accounts requires that we account for costs by unit of property. Thus, when we replaced a unit of property, for example the condensate demineralizer system, it was appropriate to account for the costs in a single work order, even though that system served both LCM and EPU purposes. As Mr. Sparby testified, the accounting should follow the project and not visa-versa.[483] For each of these reasons, we believe our accounting was appropriate.

c. Transparency Concerns Overstated

The Company interprets the Department's criticism about our accounting methods as arising from frustration over how best to distribute the costs to the two aspects of the initiative. They suggest that since we had two Certificates of Need, we should have kept two sets of accounting records. But the grant of a Certificate of Need is in the

[482] Tr. Vol. IV (Campbell) 134:10-18.

[483] Ex. 12, Sparby Rebuttal at 8:25-9:12.

nature of authorizing a construction permit.[484] It is not an accounting order and the Certificate of Need statute does not dictate the way utilities account for their costs, which are accounted for through the FERC uniform system of accounts and recovered through rate proceedings. The fact that the Company had two Certificates of Need that impacted different aspects of the same work did not create a requirement to account for that work separately. Until this proceeding, the Company had no way of knowing that the Department had such an expectation.

Further, it is important to keep in perspective that the 2005 ISFSI Certificate of Need was the first of its kind that required an economic analysis of an operating power plant. And the 2008 EPU Certificate of Need was unique in that it was a subset of ongoing work at the Plant. All of this is different from a "normal" Certificate of Need for a new plant or transmission line, where the costs for a project are related to the plant. So to the extent there is a concern over Commission policy, we believe the unique circumstances here would not implicate the Commission's broader policy considerations of how to treat costs at the Certificate of Need stage.

This issue really revolves around whether the Company should have allocated costs between the two aspects during implementation. This is a valid question and the Company could have done so, although that would not have been an accounting issue but rather a functional categorization (along the lines of what has been provided in this proceeding). An allocation by functionality (LCM v. EPU) is not an accounting effort,[485] but rather an engineering effort.[486] Moreover, that process would likely have

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[484] The Minnesota Court of Appeals adopted this view in *In re Excelsior Energy, Inc.*, 782 N.W.2d 282 (Minn. St. App. 2010). The Court stated:

> The certificate-of-need evaluation applies only to *proposals* to construct large energy facilities. Minn. Stat. § 216B.243, subd. 2 ("No large energy facility shall be *sited or constructed* in Minnesota without the issuance of a certificate of need."). . . . . The certificate of need has no bearing on a large energy facility's contractual agreements.

In re Excelsior Energy, Inc., 782 N.W.2d at 295 (emphasis in original).

[485] Tr. Vol. III (Jacobs) at 99:1-4.

been subject to adjustment as new costs emerged and had to be categorized or re-categorized all the way through completion of the Program. Finally, this exercise would likely have resulted in largely the same LCM/EPU discussion in this record.

d. Cost-Effectiveness Impact

The Department argues that had we separately allocated the LCM and EPU costs, we would have been able to alert the Commission sooner about the costs and whether the EPU remained cost effective. The Company respectfully disagrees, as this assumes we would have used the Department's conclusions about the right LCM/EPU split, as discussed earlier in this Initial Brief.

Nor would different accounting have signaled that we suspend or abandon the effort. As described in Mr. Alder's 'To-Go' analysis described in his Direct Testimony, the Program always remained beneficial to customers. We also provided evidence that we revisited the costs in both 2010 and 2011 to assess whether and how to proceed. All of the analysis we provided in this record and our contemporaneous work pointed to the same result: there was no hypothetical exit ramp and it was prudent for us to complete the effort, regardless how the accounting was structured.

e. Department's Example

On page 78 of its Initial Brief, the Department cites to the Company's answer to an information request in the rate case as an example of the Company accounting for work in separate work orders.[487] The Department's reference to this information request response actually supports the Company's position here.

Review of Exhibit 315, Schedule NAC-S-3 shows that, similar to this initiative:

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[486] Ex. 3, O'Connor Direct at Schedule 29 at 2. "[W]e relied on the judgment of the Monticello engineering to apportion the costs between unavoidable LCM and avoidable EPU based on the nature of the vendor services necessary to complete each modification."

[487] Department Initial Br. at 78; Ex. 315, Campbell Surrebuttal at Schedule NAC S-3.

> The plant has many other systems that need to be maintained. If not addressed with capital projects, the safety and reliability of the plant could be affected. These projects include the upper boiler area (reheater), demineralizer, fans, controls and a feedwater heater.[488]

The attachment to this Schedule to Ms. Campbell's Surrebuttal Testimony goes on to provide specific references to the separate work order for each unit of property being worked on. Like our normal practice, this work is accounted for by unit of property as shown in the second column (Description). A cursory comparison of Exhibit 315 (Campbell Surrebuttal), Schedule NAC-S-3 with Exhibit 16 (O'Connor Surrebuttal) Schedule 1 shows that the *accounting* is the same – by work order and unit of property.

It is true that in the rate case information request the Company provided additional columns of information asked for by the Department, including a column describing the justification for the work. That descriptive text does not change the accounting classifications and merely provided context for the costs being described, in a manner very similar to the justification descriptions the Company provided in this case for allocating the work between LCM and EPU activities.[489] In sum, our accounting for the Program was appropriate, consistent with Commission requirements, and no cause of cost increases.

3. Human Performance and Other Criticisms

The Department argues on pages 80-82 of their Initial Brief that "human performance errors" have led to higher Program costs and could result in delay. However, the Department's citations to the record do not support this proposition.

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[488] Ex. 315, Campbell Surrebuttal at Schedule NAC S-3 at 2.

[489] Ex. 9, O'Connor Rebuttal at Schedules 30 and 31 (provides descriptions and allocations for LCM/EPU split).

The NRC issued a finding of "human performance" issues at the Plant that did not relate to the implementation of the LCM/EPU Program;[490] The fact that this finding was unrelated to the LCM/EPU Program is laid out in Ms. Campbell's Schedule NAC-2 attached to her Direct Testimony, Exhibit 313. As Ms. Campbell acknowledges, "[t]he Company also noted that the external flooding procedure was corrected and human performance issues (which are contained on a fairly long list on pages 3 to 5 of the Company's response that appears to include the welding test canister issue) are being corrected with the NRC."[491] Ms. Campbell's Surrebuttal Testimony states only her general concern that "nuclear operations costs will be higher due to increased NRC review and required responses to NRC."[492]

There is no suggestion in this record that the human performance issues raised by the NRC impacted the costs of the LCM/EPU Program at all. The examples cited in Ms. Campbell's testimony all pertain to issues unrelated to the Program and that arose *after* the Program's installations had been completed.

Fundamentally, the purpose of this proceeding is not to undertake a global review of the Company's nuclear operations or to address unrelated issues. While the Company takes the NRC's concerns very seriously and we are working diligently to resolve them, they did not impact the LCM/EPU Program costs.[493]

F. Weighing the Evidence

In reaching a decision in this case, the ALJ and the Commission will have to weigh the evidence presented and determine whether the Company acted imprudently and,

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490 Ex. 16, O'Connor Surrebuttal at 35:18-36:11; Ex. 313, Campbell Direct at 3:23-24; Ex. 436, Campbell Opening Statement at 1.

491 Ex. 313, Campbell Direct at 4:17-20.

492 Ex. 315, Campbell Surrebuttal at 8:2-3.

493 Ex. 9, O'Connor Rebuttal at 33:9-15.

if so, whether that imprudence caused ratepayer harm. In doing so, the Company urges that the ALJ and the Commission focus on the facts and not on assumptions.

In weighing the evidence, the ALJ and the Commission should consider the record we developed. We provided the record with details and specifics about our performance. We provided data on what we spent money on, what we got for our money, why costs went up and the factors that influenced our implementation.[494] We provided literally thousands of documents in discovery on all aspects of our performance to facilitate a careful review of our performance.[495] These documents included the nuclear project authorizations that described alternatives considered and gave authorization to enter into contracts associated with the initiative. We also provided detailed engineering materials showing how we designed the modifications, daily status reports for the outages, oversight committee presentations, and installation, scope change and interference information. We worked cooperatively with the Department to give them the opportunity to ask for more information in discovery.[496] And we actually responded to more than 160 detailed information requests on all aspects of the Program. In short, we provided significant data designed to facilitate a probing review of our costs and actions to determine whether we were imprudent.

While we think our explanations for our costs show our performance to be within the zone of reasonableness, we fully expected Parties to debate the quality of those decisions and propose any disallowances based on specific issues. However, rather than use the extensive and detailed information we provided with our filing and in discovery, the Parties rely on high-level assumptions that since our costs went up it

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[494] In light of the prudent investment standard, we anticipated that parties would probe the details of our decision-making process and implementation effort. We expected we would have to defend against specific charges of imprudence and the consequences for those specific decisions or actions.

[495] Tr. Vol. III (Jacobs) at 101-03.

[496] Tr. Vol. III (Jacobs) at 102:24-103:2.

must have been from "mismanagement." Dr. Jacobs relies almost exclusively on a single document – the NRC Enclosure 8 – to support his positions on the LCM/EPU split; Mr. Crisp focuses only on the 2011 Cost History to support his criticisms of our project implementation; and none of the other witnesses address the substantial documentary and testimonial evidence we provided. In assessing the evidence in this case, the ALJ and Commission should keep this in mind.

1. No Expert Testified to Imprudence

In preparing its case, the Company relied upon the prudent investment standard, which requires a finding of imprudence to support imposition of a remedy.[497] Under the prudent investment standard, any disallowance must be supported by evidence establishing that the specific acts of imprudence caused harm to ratepayers.[498]

Without a finding of imprudence, there is no legal basis to implement a remedy – as identified by the United States Circuit Court for the District of Columbia. In *Violet v. Federal Energy Regulatory Commission*,[499] the Court observed that an expensive nuclear investment that was eventually abandoned did not itself make the investment imprudent.[500] On that record, there was "little if any evidence" that NEP would have pursued a different course had a different agreement been in place.[501] As such, without imprudence no remedy is warranted. We believe there is similarly "little if any

497 Ex. 425, *Final Order Approving Nuclear Cost Recovery Amounts for Fla. Power & Light Co. and Duke Energy Fla., Inc.*, Fla. Pub. Serv. Comm'n No. 130009-EI, at 35 (Oct. 18, 2013) (Florida Commission rejects Dr. Jacobs' proposed disallowance because of "concerns regarding the application of hindsight analysis and an inability to distinguish between prudent and imprudent actions").

498 *See Potomac Elec. Power Co.*, 661 A.2d at 141-42; *State ex. rel. Associated Natural Gas Co.*, 954 S.W.2d at 530 (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers); *New England Power Co.*, 31 FERC 61,047 at 61,089 n.38 (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers)).

499 800 F.2d 280 (1st Cir. 1986).

500 *Violet*, 800 F.2d at 283. In determining whether NEP should recover costs, the United States Court of Appeals for the First Circuit applied the prudence test, under which a utility is entitled to recover its costs if it acted prudently in incurring those costs. *Violet*, 800 F.2d at 282-83.

501 *Violet*, 800 F.2d at 283.

evidence" that could support a finding of imprudence. At no point has anyone done anything but speculate that had we made different decisions, we might have saved money on behalf of customers.

Mr. Crisp was the primary witness who testified as to the Company's implementation effort of the LCM/EPU Program. The Department, OAG and XLI all rely on his testimony in supporting their call for a disallowance. However, Mr. Crisp was quite categorical that, despite being the witness examining the Company's Program management, he did not reach any conclusions about prudence or imprudence:

> Q. You're not testifying in your prefiled testimony as to the prudence or imprudence of Xcel Energy's decisions on the LCM/EPU program; correct?
>
> A On the prudence of the costs?
>
> Q Yes.
>
> A That's correct.
>
> Q And the prudence of various decisions as well; isn't that right?
>
> A Not on the prudence, that's correct.[502]

Mr. Crisp was critical of the Company's performance and stated that our actions resulted in higher costs. However, he repeatedly acknowledged that cost increases do not equate with imprudence[503] and there can be many reasons why costs go up. For example, Mr. Crisp admitted that he was *not* testifying that the Company's decision to employ a parallel track approach was imprudent.[504]

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[502] Tr. Vol. III (Crisp) at 15:11-21.

[503] Tr. Vol. III (Crisp) at 17:20-22.

[504] Tr. Vol. III (Crisp) at 16:8-17:22; *see* Ex. 9, O'Connor Rebuttal at Schedule 1 (IR wherein Crisp not critical of parallel path).

Nor did Dr. Jacobs conclude that the Company's decisions or actions were imprudent. While he was critical of the Company's initial scope and argues that we could have done a better job of foreseeing the true scope of the effort, he carefully avoids calling the Company's decisions or actions imprudent. Indeed, when given the ultimate question, he admitted:

> Q. And is it your opinion that when costs are substantially above initial estimates for a nuclear project, the she[e]r fact of an increase should lead to a presumption that the increase was imprudent?
>
> A No, I don't believe so . . . .[505]

Neither did Mr. Shaw nor Ms. Campbell provide expert testimony of the Company's "imprudence" in the management and implementation of the Program. To the extent that they were critical of our Program performance, it was based on the testimony of Mr. Crisp and Dr. Jacobs. Further, neither Mr. Shaw nor Ms. Campbell are engineers and their testimony would not support a finding of "imprudence" as to the decisions and actions the Company took to implement the LCM/EPU Program.

Mr. Lindell for the OAG does purport to conclude that some of the Company's actions were "imprudent." Mr. Lindell is also not an engineer. And his experience in the construction industry was limited to back office duties 25 years ago.[506] His derivative interpretation of Mr. Crisp's testimony would not support a finding of imprudence, particularly when Mr. Crisp repeatedly disclaimed any such opinion.

[505] Tr. Vol. IV (Jacobs) 31:6-11.

[506] Tr. Vol. IV (Lindell) 97:21-25.

The lack of competent expert testimony supporting a finding of imprudence leaves the Parties attempting to design a proxy remedy based on the assumption that costs could have been less had the Company managed things differently.[507]

2. Company's Experts Support Prudence

In contrast, the Company's expert testimony was substantial and detailed. Mr. O'Connor provides a thorough and detailed defense of all of the Company's decisions and actions in this case which we have described in detail in both this Reply Brief and in our Initial Brief. That analysis will not be repeated here.

Moreover, Company expert testimony on the question of prudence was substantial, substantive and credible.[508] Mr. Stall thoroughly examined the Company's design and performance and found it to be prudent. Mr. Stall's detailed direct testimony (also ignored by the Parties) summarizes his opinions:

> Second, it is my professional opinion that the scope and design for both the life extension and uprate aspects of Xcel Energy's initiative were both reasonable and prudent.
>
> - Safety and NRC compliance considerations required Xcel Energy to undertake an expanded scope of work and upgrade or replace more systems than expected at the early stages of the project.
>
> - The design decisions made during the project were driven to substantially improve the performance of the plant, strengthen safety margins and maximize the plant's potential for operation through 2030. These decisions led to increased costs.
>
> - Xcel Energy's scope choices were an important reason why the overall initiative cost more than the initial estimates. Xcel Energy

[507] *See Potomac Elec. Power Co.*, 661 A.2d at 141-42; *State ex. rel. Associated Natural Gas Co.*, 954 S.W.2d at 530 (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers); *New England Power Co.*, 31 FERC 61,047 at 61,089 n.38 (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers)).

[508] Unrebutted credible expert testimony should be binding. *See Trisko*, 566 N.W.2d at 356.

chose a large scope of work so it is not surprising that the cost would be high. Some replacements were a matter of simple use of components Xcel Energy knew needed to be replaced. Other replacements were determined to be necessary as the design process progressed and we learned that the some systems were more worn than Xcel Energy had foreseen. Still other modifications were driven by key design decisions to support the uprate and ensure enhanced reliability through 2030.

- In reviewing the alternatives, I conclude that Xcel Energy made appropriate scope choices and design decisions that led to improved nuclear safety and operational performance of the plant.

Third, in my professional opinion, the scope of work ultimately implemented by Xcel Energy was appropriate to serve the twin goals of LCM upgrades to support an additional 20 years of operation and the EPU upgrades to support the uprate.

- It would have been highly inefficient if Xcel Energy focused narrowly on the uprate tasks without regard to life extension tasks because Xcel Energy would still have had to replace many systems on the basis of applicable nuclear safety, aging management, and reliability considerations.

- By including upgrades that were designed to enhance overall reliability of the plant through 2030, Xcel Energy incurred some costs sooner than it might otherwise have done without the EPU, but by combining LCM and EPU work, it achieved a more efficient result than had these modifications been pursued at separate times.[ ]

- Aging plant considerations drove many of the costs incurred by Xcel Energy. The scope of the work installed was not in excess of what would otherwise have been required over the planned life of the plant. Future work was avoided by utilizing this strategy.[509]

Likewise, based on his 40 years of experience, including prudence reviews of six different nuclear power plants,[510] Mr. Sieracki found Mr. Crisp's criticisms to be

[509] Ex. 4, Stall Direct at 4:9-6:2.

[510] Ex. 11, Sieracki Rebuttal at 1:19, 3:3-4.

largely unfounded and the Company's performance reasonable. Overall, Mr. Sieracki's review of the Program led him to the overall conclusion that:

> the cost growth on the LCM/EPU Program is attributable to additional work with the modifications, which happens on projects where design and implementation are occurring concurrently. The cost growth is not due to poor management. As previously discussed, Xcel Energy management decisions that affected cost were reasonable and prudent.[511]

This overall opinion was supported by significant analysis and review of many of the Company's specific decisions and actions.[512] In short, the Company met its burden of proof, demonstrating that the Program costs were prudently incurred.

IV. PROPOSED REMEDIES

While the Company does not believe the record supports a remedy in this case, we provide a discussion of the potential remedies proposed on this record for consideration, in the event the Commission finds imprudence. Specifically, the Department, OAG and XLI all offer different remedies in their cases and in this section, we explain why each of their proposed remedies should not be adopted. We identify specific facts showing that the Department, OAG and XLI have not supported a remedy on this record.

A. Parties' Proposed Remedies

1. Denying Return and Cost Caps

The OAG and XLI both support variations of cost caps and denying the Company a return on some portion of its prudent investment in Monticello. Neither of these proxy remedies are supportable under the prudent investment standard or this record.

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511 Ex. 11, Sieracki Rebuttal at 60:2-6.

512 Ex. 11, Sieracki Rebuttal at 5:15-17; 5:24-6:5; 7:5-8; 13:15-18; 29:15-18; 30:5-7; 31:18-20; 45:16-17;47:9-11 and 47:22-23.

a. Use of Proxy Remedy

The OAG points to the Commission's 2008 rate case order to support its position. The OAG argues that the Commission countenanced a proxy remedy when the record was unclear as to the amount of adverse ratepayer impact that had occurred.[513]

Reliance on the Commission's decision in our 2008 rate case is misplaced. First, in that case, the Commission had actually found the Company to have acted wrongfully by over-allocating service company costs to Minnesota customers. Unlike the present case (where the Parties cannot maintain imprudence based the record), the Commission was not left to speculate about whether the utility's conduct called for a remedy, but rather only had to design a remedy that overcame the actual deficiency.[514] A proxy should not be used to deny the Company recovery simply because costs increased and without a finding of imprudence.[515]

Second, a proxy remedy was used in that case because the nature of the overcharge made it indistinguishable. Compare that situation to the facts here where the Parties have not pursued specific costs to disallow. Instead, the Parties suggest that because they did not find imprudence or tie specific dollars to imprudent actions, a proxy remedy should be used. We respectfully submit that no specific harm or proposed disallowance was identified because there was no imprudence, making a remedy unnecessary and inappropriate.

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513 OAG Initial Brief at 9 and n.46 (citing *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 18 (Oct. 23, 2009)).

514 Mr. Alders provides testimony on the potential use of a way to implement a remedy in the event that imprudence is found. Ex. 15 Alders Surrebuttal at 25:21-28:10.

515 *N. States Power*, 344 N.W.2d at 378 ("In order to establish 'just and reasonable' retail rates, the MPUC must consider the right of the utility and its investors to a reasonable return, while at the same time establishing a rate for consumers which reflects the cost of service rendered plus a 'reasonable' profit for the utility. To accomplish this purpose, the MPUC must ascertain the operating expenses, or cost of service, of the utility." (citations omitted); *see Minnegasco v. Minn. Pub. Utils. Comm'n*, 549 N.W.2d 904, 908-909 (Minn. 1996) (same).

b. OAG's Proposal Confiscatory

The remedy urged by the OAG is unsupported, disproportionate and confiscatory. First, the OAG mixes apples and oranges in its proposed remedy. It takes the total capital costs in this case ($665 million in 2013 dollars) and adds AFUDC ($83 million) for a total of $748 million. The OAG then simply subtracts the low end of the Certificate of Need estimate of $320 ($2008$) to come up with the amount of $428 million that the OAG claims should be at risk.[516] Without analysis or acknowledging that effects of inflation need to be handled equally on both sides of the equation, the OAG declares that 75 percent of the overage ($321 million) should be disallowed outright and that the remainder should be denied a return on our investment. [517] This would have at least a $58 million revenue requirement reduction on a Total Company basis ($42.9 to $38.4 million on a Minnesota Jurisdictional basis) beginning in 2015.[518]

Second, while the OAG recites the prudent investment standard, the remedy it proposes is contrary to that standard. It ignores the reasons why our costs increased and disregards the record showing that the costs, while higher than predicted, were explainable and fully explained on this record.

And the OAG's rough-cut remedy ignores that our experience was fully consistent with the issues faced by other utilities and that other regulatory commissions, such as the Florida Commission, allowed 100 percent recovery of even larger cost increases.[519] The record demonstrates that our experience at Monticello was also fully consistent with that of several plants around the country and that the cause of our cost increases

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[516] As described in Mr. Alders' Surrebuttal Testimony, it is necessary to adjust the $320 million ($2008$) to today's dollars and to add AFUDC to that amount in order to come up with an apples-to-apples comparison. As Mr. Alders calculates, the correct apples-to-apples comparison is $453 million, making the effective comparable cost increase to be $295 million ($748-$453). Ex. 15, Alders Surrebuttal at 15:9-15.

[517] Using the more accurate apples-to-apples comparison, the difference would be $295 million ($748 million minus $453 million) and 75 percent of the overage would be $221 million.

[518] Department Initial Br. at 12.

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

was an industry-wide change and not imprudence on our part.[520] A general disallowance of this magnitude without specific facts supporting imprudence or harm would signal the investment community that our nuclear programs do not have strong regulatory support in Minnesota.[521]

c. XLI's Proposal Unsupported

XLI takes a different although equally infirm approach in designing a proxy remedy for perceived mismanagement. XLI did not actively participate in the hearing, did not sponsor any witnesses, and did not cross-examine witnesses. Nevertheless, they propose a remedy based on the Department's analysis. XLI makes a mistake similar to the OAG's by assuming that because costs went up, all of those costs should be at risk in hindsight. Rather than propose an outright disallowance, XLI proposes that the Company be denied any return on its investment for the $428 (or $295 using only 2013 dollars) million increase, which will result in a substantially larger impairment of the Monticello asset than the Department's approach.

Denying a return on the costs in excess of $320 million results in a $25.796 million revenue requirement reduction (Minnesota Jurisdictional basis) beginning in 2015. If the adjusted number is used, the costs in excess of $453 million would still result in around $20 million revenue requirement reduction (Minnesota Jurisdictional basis) beginning in 2015.

d. Retroactive Cost Caps Unreasonable

Further, a cap of costs or of the return on those costs based on Certificate of Need-level information (as explicitly argued by the OAG and implicitly argued by XLI) would represent a fundamental shift in the regulatory framework that has guided

[520] Ex. 3, O'Connor Direct at 24 and Table 3.

[521] Ex. 12, Sparby Rebuttal at 33:11-15.

traditional prudence review under the prudent investment standard.[522] While the Company recognizes that in recent years there has been considerable debate over the quality of cost estimates at the Certificate of Need stage, that debate substantially post-dates the 2008 EPU Certificate of Need proceeding and there was no discussion in that case about whether our costs should be capped.[523]

While there may be circumstances, such as competitive bidding and wind farm construction, where a different policy choice could be made on a going-forward basis, imposing a cost cap retroactively in this proceeding, would be inappropriate and inconsistent with the record and standard regulatory practice at the time.[524] Retroactive changes of this type are also not supported by Minnesota law.[525]

2. Cost-Effectiveness Remedy Unsupported

The Department takes the approach of designing a proposed "cost-effectiveness" remedy. The Department argues (i) they did not need to find imprudence because it was too difficult, (ii) unspecified "mismanagement" and poor initial cost estimation was sufficient to support a remedy, and (iii) the remedy should be tied to the Department's cost-effectiveness calculation comparing the after-the-fact cost effectiveness of the EPU to alternatives considered in the 2008 Certificate of Need proceeding. This is based on "the Department's preferred break-even remedy of

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[522] Ex. 12, Sparby Rebuttal at 12:21-24.

[523] At the Certificate of Need stage at the time, a "*number of potentially significant costs are omitted, such as environmental mitigation expenses*, which cannot be known until after the EQB's routing procedure is complete. While these estimates may be sufficient for purposes of making a decision regarding need, they cannot form the basis for determining eligibility for cost recovery." Ex. 15, Alders Surrebuttal at 17:8-13 (quoting *In the Matter of the Application of N. States Power Co. d/b/a Xcel Energy for Certificates of Need for Four Large High Voltage Transmission Projects in Sw. Minn.*, No. E002/CN-01-1958, REPLY TO XCEL ENERGY'S MOTION TO LIMIT THE SCOPE OF EVIDENCE OF THE MINNESOTA DEPARTMENT OF COMMERCE at 4 (Apr. 25, 2002)).

[524] Ex. 15, Alders Surrebuttal at 2:15-19.

[525] "Indeed, the Public Utility Act expressly prohibits retroactive ratemaking." *Peoples Natural Gas*, 369 N.W.2d at 533 (citing Minn. Stat. § 216B.23, subd. 1 ("Whenever upon an investigation . . . the commission shall find rates, tolls, charges, schedules or joint rates to be . . . unreasonable or unlawful, the commission shall determine and by order fix reasonable rates, tolls, charges, schedules, or joint rates to be imposed, observed, and followed in the future)).

disallowing only those costs that would render the Monticello plant not to be cost effective on a present basis for a $10.237 million revenue reduction (Minnesota Jurisdictional basis) beginning in 2015."[526] The Department's proposed cost-effectiveness disallowance has several problems and should not be adopted.

a. *Valid Inputs Required*

First, this remedy applies hindsight by superimposing 2013 actual costs ($748 million with AFUDC) and Dr. Jacobs' 14.3/85.7 percent LCM/EPU split on 2008 assumptions, an approach that is inconsistent with the prudent investment standard and disallows costs because they went up, not because of imprudence. Monticello remains "overwhelmingly cost-effective as a whole"[527] and on that basis alone, the cost-effectiveness remedy would result in no disallowance. As argued earlier in this Brief, even if the Company had come up with a higher initial estimate, it would not have changed the decision to go forward. And on this record, the only potential higher initial estimate that could have been considered was about $420 million,[528] which again remains overwhelmingly cost effective based on Mr. Shaw's analysis.

Even if a split of costs between the LCM and EPU aspects is imposed, the cost-effectiveness remedy results in no disallowance using any reasonable split. Mr. Shaw acknowledged that using the 58.4/41.6 LCM/EPU split that was used during the 2008 Certificate of Need proceeding results in the EPU megawatts being cost effective by $112 million, even using the hindsight total costs. Table 13 from Mr. Shaw's Direct Testimony illustrates this point:[529]

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[526] Department Initial Br. at 12-13.

[527] Ex. 309, Shaw Direct at 14:1-2.

[528] Ex. 9, O'Connor Rebuttal at 44:25-45:6; Ex. 8, Alders Rebuttal at 19:17-20.

[529] Ex. 309, Shaw Direct at 27:2.

Table 13: 42 Percent EPU-2008 Base Year (Corrected Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,286
Monti Fuel	$582
Monti Total	$2,781

Monticello LCM 58%	PVSC Results $millions
Monti Retirement (2031)	$96
LCM + Ongoing Capital	$563
Monti O&M	$1,286
Monti Fuel	$582
Replacement Capacity	$74
Replacement Energy	$237
Incremental Emissions	56
Total Costs	$2,893
Net PVSC (Benefits)/Cost	**($112)**

b. Dr. Jacobs' Hindsight Split

It is only when the Department uses Dr. Jacobs' 14.3/85.7 percent LCM/EPU split that the cost-effectiveness remedy works in the Department's favor. But as we have demonstrated in both our Initial Brief and in this Reply Brief, Dr. Jacobs' proposed split bears no relationship to the facts and circumstances at the Plant, as his split completely ignores all of the work that needed to be done for LCM purposes irrespective of the uprate. The substantial record evidence demonstrates that any reasonable split would more accurately account for the LCM work that needed to be undertaken regardless of the uprate.

This same type of 'breakeven' analysis[530] was specifically rejected by the Florida Commission "because there is no support regarding how, if at all, [Dr. Jacobs'] use of a breakeven analysis does not apply hindsight analysis and distinguishes between prudent and imprudent utility management actions."[531] Using an arbitrary and after-the-fact "EPU-centric" split involves precisely the same flaws that were rejected in Florida.

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[530] Tr. Vol. III (Jacobs) at 110:12-16.

[531] Ex. 425, *Final Order Approving Nuclear Cost Recovery Amounts for Fla. Power & Light Co. and Duke Energy Fla., Inc.*, Fla. Pub. Serv. Comm'n No. 130009-EI at 36.

B. Identified Categories of Costs

The Company provided a variety of cost measurements to assess the quality of our performance. This provides record data sufficient for the ALJ and the Commission to make an assessment of the prudence of our effort on a variety of decisions and actions. To the extent that our performance falls short based on these items, we believe it would be more appropriate to address the costs found to have been imprudently incurred rather than to rely on any proxy.

We note that the OAG in its Initial Brief provides some discussion on these items.[532] Specifically, the OAG argues:

> The Company measured $25 to $30 million in expenses for field changes; $13 million for duplicative design; and $11 million for abandoned work. Some of these costs would have been avoidable if the Company had acted prudently in preparing its design and scoping. It is difficult to measure the total amount of avoidable costs because Mr. O'Connor claimed, unreasonably, that only $1 million in field changes were avoidable.
>
> But it is clear that expenses for duplicative designs and abandoned costs could have been reduced with proper design and scoping. The OAG recommends that the Commission disallow 50 percent of the duplicative design and abandoned costs, as well as 25 percent of the expenses for field changes, for a total disallowance of $19.5 million.[533]

While we disagree with the OAG's conclusions on these items, we agree that they identified issues that can be considered in making a decision about prudence and designing a remedy if imprudence is found.

The Company provides the following Table to summarize these categories. Each category is discussed below.

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[532] OAG Initial Br. at 26, 41-42.

[533] OAG Initial Br. at 41-42; *see* OAG Initial Br. at 26.

Potential Avoidable Costs[534]

Cost	Description	Potential Additional Costs	OAG Proposed Imprudence Disallowance
Potentially Duplicative Designs	Reasonably moved work to alternative designer to keep work on track and maximize skill and that about $13 million of that was overlapping other vendors' scope.[535]	$13 million	$6.5 million
Abandoned Work	The Company identified work totaling about $11 million was not fit for the intended purpose for various reasons.[536]	$11 million	$5.5 million
Field Change Orders	Field changes of about $25-30 million were unavoidable and mostly could not have been found ahead of time[537]	$1 million	$7.5 million
Total		**$25 million**	**$19.5 million**

1. Potentially Duplicative Designs

On this record, we considered whether we had undertaken duplication of design effort. As described in Exhibit 9 (O'Connor Direct), Schedule 28, the Company did an analysis to determine whether and how much of the design work we undertook was potentially duplicative. It is certainly true that the Company had occasional situations where we pulled one designer off the job and replaced them with someone with more targeted experience. For example, we had an instance where we rejected a design because we concluded it was not fully functional and we would have real problems actually constructing it. In that instance we brought in an alternative designer to come up with a more feasible design.[538] By doing so, we saved approximately $6.6 million dollars by pulling work from one designer and giving it to

534 No party has challenged that we completed the right modifications or any specific costs incurred in their installation. As a result, we have not included those costs in this table but have focused on the identified costs that relate to the claims of mismanagement in parties Initial Briefs.

535 Ex. 9, O'Connor Rebuttal at 79:7-16, 79:18 at Table 9; Ex. 10, O'Connor Rebuttal at Schedule 28 at 3-5 (Non-Public).

536 Ex. 9, O'Connor Rebuttal at 80:17-26 and Schedule 29.

537 Ex. 9, O'Connor Rebuttal at 75:7-77:11 and Schedule 27.

538 Ex. 9, O'Connor Rebuttal at 42:16-21.

another.[539] We also saved about $2.2 million by changing HVAC system designs and moving the work to a different designer,[540] a designed a "contamination free" zone to facilitate access for our workers which resulted in material cost savings during the 2011 outage.[541]

Nevertheless, despite saving nearly $10 million from these examples, we undertook an analysis to assess the impact of moving designs from one vendor to another. As Mr. O'Connor states:

> First, I reviewed the Company documents to determine the scope of work performed by these vendors to determine if it was all design-related or not. As an example, some vendors provided planning personnel as additional outage resources. This is not design-related and all similar non-design-related costs were removed from the analysis. Second, I made a determination of whether the subsequent design-related work paid for by the Company was part of the original scope or not. The dollars associated with the work that was potentially part of the original design scope form the pool of potential dollars associated with Mr. Crisp's criticisms, as the dollars for the expanded scope would have resulted in a change order.[542]

Mr. O'Connor concluded that there was approximately $13 million of potentially duplicative designs.[543] This analysis confirms that the Company's extra design effort was offset by benefits we obtained.

2. Abandoned Work

Another category we identified was 'abandoned' or 'unusable' work. In a major six-year construction effort, it is hardly surprising that the Company would encounter

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[539] Ex. 9, O'Connor Rebuttal at 42:19-21; 62:25-63:8.

[540] Ex 9, O'Connor Rebuttal at 63:12.

[541] Ex. 9, O'Connor Rebuttal at 61:16-21.

[542] Ex. 9, O'Connor Rebuttal at 79:7-16 and Table 9.

[543] Ex. 9, O'Connor Rebuttal at 79:18-19 at Table 9.

some components and other items that did not serve the intended purpose. The fact that this work was "abandoned" does not connote wrongdoing or mismanagement.[544] As Mr. O'Connor states:

> The Company also identified work that was ultimately not fit for its intended purpose because of scope changes, changes in NRC requirements, changes in design, or other reasons. However, this work may have had other purposes or been a part of a necessary process to optimize the final design of LCM/EPU modifications. The Company quantified this work in response to an Information Request from the Office of the Attorney General during the 2012 rate case. I have attached a copy of the Company's response as Exhibit ___ (TJO-2), Schedule 29. This work totaled approximately $11 million.[545]

3. Field Changes

Finally, the Company did an analysis of field design changes in response to the criticisms about the difficulty of the installations and the need to address undisclosed interferences and hidden rebar and other field changes. Again, we approached this effort from the perspective of trying to determine if we had done things differently we may have been able to save money. What we found, however, is that the costs we incurred were substantially the same as what we would have incurred in any event.

We identified approximately 2,000 field changes that resulted from discrepancies in as-found conditions at a total cost increase of about $25-30 million.[546] To quantify a potential cost savings that may have resulted from earlier planning for what subsequently became the field changes, the Company undertook a multi-step analysis, as described by Mr. O'Connor:

> Initially, I segregated the changes by the three groupings: basic field changes, intermediate field changes, and complex field changes. I then

[544] Ex. 9, O'Connor Rebuttal at Schedule 29 at 1.

[545] Ex. 9, O'Connor Rebuttal at 80:19-26.

[546] Ex. 9, O'Connor Rebuttal at Schedule 27.

> selected a sample of field changes, I reviewed each from the perspective of whether the particular field change could have been identified prior to the outage when it was discovered. This required segregating the samples into two categories, those that could have reasonably been identified pre-outage based on the level of planning and design Mr. Crisp suggests and those that could not. For those that could not, no further analysis would be required.
>
> Further, for those field changes that reasonably could have been identified pre-outage, I attempted to determine if a different, less costly fix could have been developed before the outage. Based on the results of that analysis, I was able to estimate a potential cost savings from the sample analyzed. [547]

The conclusion of this analysis is that the vast majority of field design changes could not have been avoided and that for the ones that could have been avoided, the Company would have realized only a modest cost savings of no more than $1 million. The OAG's Initial Brief declares without support that Mr. O'Connor "unreasonably" allocated $1 million as potentially avoidable.[548] However, the OAG ignores Mr. O'Connor's analysis backing up that opinion and the OAG provides no facts to support any other number. Mr. O'Connor's testimony provides a detailed explanation:

> Even at the level of design completion Mr. Crisp suggests, the types of issues we encountered that required us to undertake field changes would not have been known. For example, we encountered rebar interferences in thick concrete walls floors. Rebar is reinforcing steel that is embedded into concrete to strengthen it, which is not visible without the use of specialized equipment. While specialized equipment can detect its location within concrete, that is simply not performed at any level of design in my experience. Its location is typically discovered only as the construction work is performed.[549]

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[547] Ex. 9, O'Connor Rebuttal at 75:23-76:8.

[548] OAG Initial Br. at 41.

[549] Ex. 9, O'Connor Rebuttal at 77:1-8.

For the reasons discussed throughout our Briefs and the record evidence on which they rely, the Company does not believe that we were imprudent or that a disallowance of any material amount is warranted. If the Commission disagrees, we believe that the Potential Avoidable Costs identified in this segment of our Reply Brief represent the maximum disallowance that would be consistent with the prudent investment standard, as the Potential Avoidable Costs are the only measurable amounts in the record specifically tied to actions and decisions that caused cost increases. We respectfully submit that even if imprudence is found somewhere in the record, a full disallowance of these costs is not warranted because (i) the Company's specific actions leading to these Potential Avoidable Costs were prudent; (ii) some level of Potential Avoidable Costs are inevitable in a complex nuclear project, where unforeseeable information becomes available over the course of the project; and (iii) in some cases, the same actions that caused these cost increases reduced costs in other areas. We therefore recommend that if any disallowance is warranted, the total amount should be less than the sum of Potential Avoidable Costs.

V. CROSS REFERENCES TO THE DEPARTMENT'S ISSUES LIST

The Department provides a list of its 12 concerns with our performance on pages 72-73 of its Initial Brief. This list includes all of the items described in the Department's Initial Brief and includes the concerns raised by the OAG and XLI. Many of the 12 issues identified in the Department's list overlap with one another. In addition, the organization of the Parties' Initial Briefs does not precisely track these issues. We therefore provide this list with the hope it is a useful checklist of issues of concern and the Company's response to those issues. We therefore identify each of the Department's issues below, along with cross-references to our overall Testimony and Initial and Reply Briefs where the particular issue is discussed or rebutted.

1. Lack of upfront planning as addressed by Mr. Crisp.

This issue is discussed in the:

- Direct Testimony of Mr. O'Connor;[550]
- Rebuttal Testimony of Mr. O'Connor;[551]
- Surrebuttal Testimony of Mr. O'Connor;[552]
- Direct Testimony of Mr. Stall;[553] and
- Rebuttal Testimony of Mr. Sieracki.[554]

In addition, we cover this issue on pages 84-86, 90-91 and 97-100 of our Initial Brief and provide additional response to this criticism on pages 34-56 of this Reply Brief.

2. Effects of the "fast-track" approach as addressed by Mr. Crisp.

This issue is discussed in the:

- Direct Testimony of Mr. Alders;[555]
- Rebuttal Testimony of Mr. Alders;[556]
- Surrebuttal Testimony of Mr. Alders;[557]
- Rebuttal Testimony of Mr. Sparby;[558]
- Rebuttal Testimony of Mr. Sieracki;[559]
- Rebuttal Testimony of Mr. O'Connor;[560] and

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[550] Ex. 3, O'Connor Direct at 29:14-30:14, 45:1-51:2, 58:9-67:12.

[551] Ex. 9, O'Connor Rebuttal at 51:7-56:16;

[552] Ex. 16, O'Connor Surrebuttal at 4:14-5:18, 8:4-18:6.

[553] Ex. 4, Stall Direct at 34:26-36:7, 62:3-66:3.

[554] Ex. 11, Sieracki Rebuttal at 11:9-17:3.

[555] Ex. 2, Alders Direct at 18:5-20:15.

[556] Ex. 8, Alders Rebuttal at 6:23-12:4.

[557] Ex. 15, Alders Surrebuttal at 23:14-24:7.

[558] Ex. 12, Sparby Rebuttal at 19:9-20:15.

[559] Ex. 11, Sieracki Rebuttal at 22:3-23:24.

[560] Ex. 9, O'Connor Rebuttal at 49:15-51:2, 63:20-65:20 and Schedules 24-26.

- Surrebuttal Testimony of Mr. O'Connor.[561]

In addition, we cover this issue on pages 26-28 and 82-86 of our Initial Brief and provide additional response to this criticism on pages 39-44 of this Reply Brief.

3. Inadequate understanding of the true scope of work as addressed by Mr. Jacobs.

This issue is discussed in the:

- Direct Testimony of Mr. O'Connor;[562]
- Rebuttal Testimony of Mr. O'Connor;[563]
- Surrebuttal Testimony of Mr. O'Connor;[564]
- Direct Testimony of Mr. Stall;[565] and
- Rebuttal Testimony of Mr. Sieracki.[566]

In addition, we cover this issue on pages 33-38 and 96-97 of our Initial Brief and provide additional response to this criticism on pages 45-56 of this Reply Brief.

4. Insufficient oversight of contractors and the entire process as addressed by Mr. Crisp.

This issue is discussed in the:

- Direct Testimony of Mr. O'Connor;[567]
- Rebuttal Testimony of Mr. O'Connor;[568]
- Surrebuttal Testimony of Mr. O'Connor;[569] and

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561 Ex. 16, O'Connor Surrebuttal at 19:20-22:2.

562 Ex. 3, O'Connor Direct at 31:20-33:22, 93:5-136:11.

563 Ex. 9, O'Connor Rebuttal at 40:13-43:15, 51:7-56:16.

564 Ex. 16, O'Connor Surrebuttal at 6:9-7:19.

565 Ex. 4, Stall Direct at 36:13-61:6.

566 Ex. 11, Sieracki Rebuttal at 25:9-11, 32:7-40:17.

567 Ex. 3, O'Connor Direct at 40:17-41:17, 60:24-67:12, 71:24-92:22.

568 Ex. 9, O'Connor Rebuttal at 46:16-49:7, 60:17-61:11, 68:15-71:15.

569 Ex. 16, O'Connor Surrebuttal at 18:10-19:16.

- Rebuttal Testimony of Mr. Sieracki.[570]

In addition, we cover this issue on pages 61-75 and 104-108 of our Initial Brief and provide additional response to this criticism on pages 59-74 of this Reply Brief.

5. Start and stop process of contractors addressed by Mr. Crisp.

This issue is discussed in the:

- Direct Testimony of Mr. O'Connor;[571]
- Rebuttal Testimony of Mr. O'Connor;[572]
- Surrebuttal Testimony of Mr. O'Connor;[573] and
- Rebuttal Testimony of Mr. Sieracki;[574]
- Hearing Testimony of Mr. O'Connor;[575] and
- Hearing Testimony of Mr. Sieracki.[576]

In addition, we cover this issue on pages 104-108 of our Initial Brief and provide additional response to this criticism on pages 65-68 of this Reply Brief.

6. Poor project management as addressed by Mr. Crisp.

This issue largely overlaps with or subsumes the above criticisms regarding multi-tracking the Program, "starts and stops," contractor oversight, upfront planning and proper scoping. It is discussed in the:

- Direct Testimony of Mr. O'Connor;[577]
- Rebuttal Testimony of Mr. O'Connor:[578]

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570 Ex. 11, Sieracki Rebuttal at 25:14-31:22, 41:8-43:8.

571 Ex. 3, O'Connor Direct at 40:17-41:17, 46:16-50:27.

572 Ex. 9, O'Connor Rebuttal at 60:4-72:23.

573 Ex. 16, O'Connor Surrebuttal at 18:10-19:16.

574 Ex. 11, Sieracki Rebuttal at 43:16-50:8.

575 Tr. Vol. I (O'Connor) at 97:11-99:6.

576 Tr. Vol. II (Sieracki) at 31:22-33:4.

577 Ex. 3, O'Connor Direct at 71:24-92:22.

- Surrebuttal Testimony of Mr. O'Connor;[579] and
- Rebuttal Testimony of Mr. Sieracki.[580]

In addition, we cover this issue on pages 59-75 and 96-110 of our Initial Brief and provide additional response to this criticism on pages 56-82 of this Reply Brief.

7. Ineffective use of contingencies as addressed by Mr. Crisp.

The Company's use of contingencies is discussed in Mr. O'Connor's Rebuttal Testimony[581] and Mr. Sieracki's Rebuttal Testimony.[582] Similar to the Florida proceeding, "no evidence was presented to show that ... [the utility had the] opportunity to reduce EPU Project costs by any amount through use of a larger contingency …."[583]

In addition, we cover this issue on pages 91-94 of our Initial Brief and provide additional response to this criticism on pages 24-27 of this Reply Brief.

8. Lack of cost controls and tracking concerns as addressed by Ms. Campbell.

This issue was discussed in the:

- Direct Testimony of Mr. Weatherby,[584]
- Rebuttal Testimony of Mr. Sparby,[585]
- Rebuttal Testimony of Mr. Sieracki,[586]

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[578] Ex. 9, O'Connor Rebuttal at 21:16-23:16, 62:7-12.

[579] Ex. 16, O'Connor Surrebuttal at 22:6-9.

[580] Ex. 11, Sieracki Rebuttal at 8:10-31:22, 33:19-35:8, 37:20-40:17, 41:8-43:8, 55:24-60:6.

[581] Ex. 9, O'Connor Rebuttal at 40:3-41:15 and Schedule 13.

[582] Ex. 11, Sieracki Rebuttal at 54:16-55:17.

[583] Ex. 425, *In re Nuclear Cost Recovery Clause*, Fla. Pub. Serv. Comm'n No. 130009-EI, FINAL ORDER APPROVING NUCLEAR COST RECOVERY AMOUNTS FOR FLORIDA POWER & LIGHT COMPANY AND DUKE ENERGY FLORIDA, INC. at 34 (Oct. 18, 2013).

[584] Ex. 5, Weatherby Direct; Ex. 6, Weatherby Direct (Non-Public).

[585] Ex. 12, Sparby Rebuttal at 30:24-31:12.

- Rebuttal Testimony of Mr. O'Connor,[587]
- Surrebuttal Testimony of Mr. Alders;[588] and
- Surrebuttal Testimony of Mr. O'Connor,[589]

This issue largely is moot because Dr. Jacobs acknowledges that the issue of an LCM/EPU split, which is the focus of Ms. Campbell's concerns and which Dr. Jacobs conducted for the Department, was an engineering attribution of costs rather than an accounting exercise.[590]

In addition, we cover this issue on pages 31 and 134-135 of our Initial Brief and provide additional response to this criticism on pages 111-116 of this Reply Brief.

9. Human performance errors raised by NRC as addressed by Ms. Campbell.

The Department raises several additional issues that are unrelated to the LCM/EPU Program and which had no impact on the costs of the initiative being reviewed in this proceeding. This issue is described in the Rebuttal Testimony of Mr. O'Connor.[591] In addition, we cover this issue on pages 136-137 of our Initial Brief and provide additional response to this criticism on pages 116-117 of this Reply Brief.

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586 Ex. 11, Sieracki Rebuttal at 50:15-54:11.

587 Ex. 9, O'Connor Rebuttal at 11:15-15:15.

588Ex. 15, Alders Surrebuttal at 14:21-15:5.

589 Ex. 16, O'Connor Surrebuttal at 23:5-26:15.

590 Tr. Vol. III (Jacobs) at 98:19-99:4.

591 Ex. 9, O'Connor Rebuttal at 33:9-36:11.

10. Low cost estimates and inadequate information in initial Certificates of Need and in this case regarding necessary capital costs as addressed by Ms. Campbell and Mr. Shaw.

This issue overlaps with the contingency issue discussed above, and is discussed in the:

- Direct Testimony of Mr. O'Connor;[592]
- Rebuttal Testimony of Mr. O'Connor;[593]
- Surrebuttal Testimony of Mr. O'Connor;[594]
- Rebuttal Testimony of Mr. Alders.[595]

In addition, we cover this issue on pages 32-38 and 86-96 of our Initial Brief and provide additional response to this criticism on pages 22-30 of this Reply Brief.

11. Lack of communication by Xcel Energy with Commission and interested Parties regarding cost overruns as addressed by Ms. Campbell.

This issue was addressed in the:

- Rebuttal Testimony of Mr. Sparby;[596]
- Rebuttal Testimony of Mr. Alders;[597] and
- Surrebuttal Testimony of Mr. Alders.[598]

In addition, we cover this issue on pages 100-102 and 135-136 of our Initial Brief and provide additional response to this criticism on pages 109-111 of this Reply Brief.

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[592] Ex. 3, O'Connor Direct at 29:15-38:24.

[593] Ex. 9, O'Connor Rebuttal at 36:16-49:7.

[594] Ex. 16, O'Connor Surrebuttal at 8:4-17:16.

[595] Ex. 8, Alders Rebuttal at 12:9-13:23.

[596] Ex. 12, Sparby Rebuttal at 29:21-30:11.

[597] Ex. 8, Alders Rebuttal at 15:3-18-2 and Schedule 1.

[598] Ex. 15, Alders Surrebuttal at 10:11-15:15.

12. Lack of showing that it is reasonable to allow recovery from ratepayers of the amount of EPU project that is not cost effective as addressed by Mr. Shaw.

This issue implicates the legal questions of (i) whether the Company satisfied the relevant burden of proof under the prudent investment standard to show that the costs we incurred are reasonable under the circumstances, and (ii) whether the cost-effectiveness remedy posed by the Department is sustainable. We describe both of these issues on pages 21-75 and 137-141 of our Initial Brief and provide additional response to this criticism on pages 11-20 and 128-130 of this Reply Brief.

VI. CONCLUSION

In conclusion, the record supports a recommendation to the Commission that our implementation of the Program was reasonable under the various circumstances the Program encountered. We have satisfied our burden of proving (through the submission of substantial fact-based evidence) that our costs, while higher than we estimated, were all incurred reasonably. None of the concerns raised by the Parties in their Initial Briefs adequately rebut our substantial evidence. The Company continues to believe that this record would not support a material disallowance.

Dated: November 21, 2014

Respectfully submitted,

By _/s/__________________

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