414 Nicollet Mall
Minneapolis, Minnesota 55401

October 14, 2014

The Honorable Jeanne M. Cochran
Administrative Law Judge
Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164-0620

RE: REPLY BRIEF
XCEL ENERGY'S APPLICATION FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN THE STATE OF MINNESOTA
OAH DOCKET NO. 68-2500-31182
DOCKET NO. E002/GR-13-868

Dear Judge Cochran:

Enclosed for filing is the Reply Brief and Proposed Findings of Fact of Northern States Power Company, doing business as Xcel Energy, submitted in regards to the above-referenced matter.

We have served copies of this filing on all parties on the attached service list as provided in the Prehearing Order.

Please contact me with any questions related to the Reply Brief at (612) 215-4663 or at Aakash.Chandarana@xcelenergy.com.

Respectfully Submitted,

/s/

AAKASH H. CHANDARANA
LEAD REGULATORY ATTORNEY - NORTH

Enclosures

cc: Service List

STATE OF MINNESOTA
BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota	OAH Docket No. 68-2500-31182 MPUC Docket No. E002/GR-13-868

XCEL ENERGY REPLY BRIEF

October 14, 2014

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In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota	OAH Docket No. 68-2500-31182 MPUC Docket No. E002/GR-13-868 **XCEL ENERGY REPLY BRIEF**

I. INTRODUCTION AND OVERVIEW

Northern States Power Company, doing business as Xcel Energy, respectfully provides this Reply Brief in response to the briefs submitted by the Department, OAG, and other parties to this proceeding.[1] After reviewing those briefs, the Company continues to believe the outcome of this case remains unchanged: the Company's proposed increase in base electric rates, as modified during the course of this proceeding, should be approved.

Our Initial Brief addressed many of the arguments posed by the Parties pertaining to disputed revenue requirement issues and rate design considerations. As a result, we continue to rely on those arguments and stand-by the outcomes advocated for in our Initial Brief. In this Reply, the Company continues to focus on the five key disputed revenue requirement issues, as well as responding the arguments raised by parties regarding the other disputed revenue requirement issues. We recognize this Reply may be longer than expected; but that is due, in part, to several instances where parties raised new arguments for the first time in briefing.

[1] Initial briefs were received from (i) the Minnesota Department of Commerce (Department); (ii) the Office of Attorney General – Residential Utilities Division (OAG); (iii) the Commercial Group (CG); (iv) Xcel Large Industrial (XLI); (v) Energy Cents Coalition (ECC); (vi) Clean Energy Intervenors (CEI) (vii) the Minnesota Chamber of Commerce (MCC); (viii) the Minnesota Center for Environmental Advocacy (MCEA); (ix) the Suburban Rate Authority (SRA); (x) U.S. Energy Services, Inc. (ICI Group); and (xi) AARP.

Many of the parties, in their respective initial briefs, discussed the legal standards applicable to the Company's request for rate relief. While we recognize that rates must be just and reasonable and that the Company bears the burden of proof, it is important to be clear as to the application of these legal standards to the record. To be plain, we do not believe that the mere suggestion of doubt or employing a result-oriented approach applies these standards correctly. Thus, reliance by the parties on the subjective casting of doubt, unsupported opinions and statements of opinion is not sufficient to rebut the comprehensive record developed by the Company in support of its requested rate relief. For that reason, this Reply provides thorough discussion of the applicable standards of review of this case.

We appreciate the Department's comprehensive recitation of the record as it pertains to all issues, including those resolved between the Company and Department. While we could cavil with the characterizations of the record in the Department's Initial Brief, as it pertains to several of the issues resolved between the Company and Department, the Company is not providing a similar summary of all of the resolved issues to do so. Instead we focus on issues that are in dispute, even those that are partially resolved, such as cost recovery of the Prairie Island EPU and Capital Structure.

For those issues only addressed by the Department and Company and resolved by the Department and Company on this record, we believe these issues remain resolved, as indicated in the Department's Initial Brief. The Company continues to believe the record is complete for a finding that the resolutions reached by the Department and Company will result in just and reasonable rates.

To the extent that the ALJ or the Commission disagrees with any particular resolution, the Company notes there is a thorough record supporting its request. The sales forecast is the primary example of this. The Company and Department have reached a resolution of this issue by using actual sales data for purposes of establishing the Company's revenues during the test year. We appreciate the Department working with us reaching this resolution, which is innovative and possible due to the unique timing considerations presented by this case. While we are willing to provide December forecast data using the Department's sales forecast for informational purposes, we recognize the Commission or ALJ may elect to use some amount of forecasted data for the test year. In that situation, the question arises as to which forecast to use. In this Reply, we address the reasons supporting the use of the Company's sales forecast should forecasted data be used for the test year. Since similar principles are involved with the property tax expense resolution, we also address the reasonableness of our test year property tax forecast should the Commission or ALJ elect not to accept the resolution reached by the Company, Department and MCC.

The Company has a number of compliance obligations when it files a new electric rate case. As part of our last electric rate case, the Commission identified new compliance requirements for the Company pertaining to qualified pension expense, accounting treatment of AFUDC/CWIP, corporate aviation costs, Sherco 3, and key performance indicators for our Annual Incentive Program. With the exception of corporate aviation, which the OAG disputes, the Company believes no party is contesting its compliance with prior Commission orders, including the order from our last electric rate case. In this Reply, we respond to the OAG's arguments regarding corporate aviation, as well as providing a new section to address the Department's discussion related to our compliance with the KPI and Sherco 3 related Order Points.

The Company organizes this reply in the following sections:

- *Applicable Legal Standards* – provides a comprehensive discussion of the following legal standards: (1) just and reasonable rates, (2) burden of proof, and (3) test year requirements.

- *Key Disputed Issues* – provides a comprehensive response to the arguments raised by the Department and other parties regarding (1) ROE, (2) the Monticello LCM/EPU Project, (3) Pension, (4) Passage of time, and (5) Total labor.
- *Other Disputed Revenue Requirement Issues* – addresses several arguments including the Prairie Island EPU, CWIP and AFUDC, Nuclear Theoretical Depreciation Reserve, increasing the interest rate for interim refunds, corporate aviation costs, changes to capital projects in-service dates, and capital structure.
- *Resolved Revenue Requirement Issues* - provides the Company's reasons supporting selection of its sales forecast should the ALJ or Commission elect to use forecasted data in the test year.
- *Compliance with the Prior Commission Orders* – addresses the comments made by the Department in its initial brief as it pertains to the Company's compliance with the Commission's order in our most recent rate case.
- *Disputed Rate Design* – responds to several arguments parties made about the Company's CCOSS, revenue apportionment, decoupling and other rate design considerations.

II. APPLICABLE LEGAL STANDARDS

As part of the Company's Initial brief, we discussed the ratemaking principles and legal standards applicable to resolving the contested issues in this case. The briefs of other parties refer to some, but not all, of these principles and standards. Specifically, the Department, OAG, XLI, CG and ICI Group express concern that granting the Company's rate increase will result in unjust and unreasonable rates; the Department, OAG and XLI question whether the Company has met its burden of proof; and the Department recommends several downward adjustments for capital additions that are in tension with the representative nature of a test year. Since these parties raised these specific legal standards and the selective and incomplete application of the law to the record can be distortive, we provide this discussion of the ratemaking principles and legal standards to further facilitate review of the contested issues and record.

A. Just and Reasonable Rates

1. Balancing of Interests

The Commission's obligation to determine whether rates are just and reasonable is "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers:"[2] Balancing of interests is not unbounded. Rather, that process is subject to "established requirements" that function as "constraint[s]," as the Minnesota Supreme Court has noted.[3] Recovery of the cost of furnishing service is an established requirement.

A just and reasonable rate must "enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed."[4] This is a fundamental constitutional requirement.[5] The Commission is "bound to follow certain legal criteria in establishing a rate of return"[6] and must follow "certain guidelines … in determining an appropriate rate of return," and rates to be charged, which include recovery of the cost of service:

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[2] *In Re Request of Interstate Power Co. for Authority to Change its Rates for Gas Service*, 574 N.W.2d 408, 411 (Minn. 1998).

[3] *Hibbing Taconite Co. v. Minnesota 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 customers. (citation omitted) The United States Supreme Court established requirements for determining the rate of return in *Bluefield* … and *Hope* …, which this court has followed. One constraint enunciated by the United States Supreme Court is that the PSC cannot fix rates that are unconstitutionally confiscatory.") (Emphasis added.)

[4] *FPC v. Hope Natural Gas Co.,* 320 U.S. 591, 605 (1944).

[5] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n.*, 262 U.S. 679, 690 (1923).

[6] *Hibbing Taconite Co. v. Minnesota Pub. Serv. Comm'n*, 302 N.W.2d 5, 10 (Minn. 1980)

> "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."[7]

While the Minnesota Supreme Court has recognized the need to recover the cost of service, the Department recommends downward adjustments for the Company's pension expense and total labor expense for reasons unrelated to whether these expenses are representative and reasonable. There is no support for this position. Rather, cost of service has been recognized as a key element that must be included in just and reasonable rates, and as an objective standard.[8]

Several parties observe that Minn. Stat. § 216B.03 requires the Commission to resolve all doubts in favor of ratepayers and imply that this creates a heightened burden on the Company.[9] While the Company does not dispute application of this statute, Section 216B.03 does not provide a "trump card" or override the Commission's duty to observe the established standards in balancing the interests of all stakeholders.[10] In *Hibbing Taconite,*[11] the Minnesota Supreme Court 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.[12] In *Minnegasco,* the Supreme Court found that the fundamental basis for rate-setting is the "cost" of the utility and

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[7] *Hibbing Taconite Co. v. Minnesota Pub. Serv. Comm'n*, 302 N.W.2d 5, 10 (Minn. 1980) quoting Northwestern Bell Telephone Co. vv State, 299 Minn. 1, 5-6, 216 N.W. 2d 841, 846 (1974)

[8] *Northern States Power v, Minnesota Pub. Util. Comm'n*, 344 N.W.2d 374 (Minn.), *cert. denied*, 467 U.S. 1256 (1984) ("In order to establish "just and reasonable" 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. (citation omitted). To accomplish this purpose, the MPUC must ascertain the operating expenses, or cost of service, of the utility." at 378 (quoted in *Minnegasco v. Minnesota Public Utilities Commission*, 549 N.W.2d 904, 908-909 (Minn. 1996).

[9] Department Initial Brief at p.8-9, 77-78; OAG Initial Brief at p. 3-4, 28; XLI Initial Brief at p. 2-3.

[10] *See Hibbing Taconite Co. v. Minnesota Pub. Serv. Comm'n*, 302 N.W.2d 5, 9-10 (Minn. 1980).

[11] *See Hibbing Taconite Co. v. Minnesota Pub. Utils. Comm'n*, 302 N.W.2d 5, 9-11 (Minn. 1980) ("Chapter 216B gives to the PSC the duty as well as the power to set a just and reasonable rate after review of evidence and testimony.")

[12] *See also Northern States Power Co. v. Minnesota Pub. Utils. Comm'n,* 344 N.W.2d 374 (Minn. 1984) (ratepayer protection theory rejected and Commission was required to allow utility to recover specified costs).

rejected an argument that Minn. Stat. § 216B.03 overrode other standards.[13] We therefore ask the ALJ to apply the legal standards neutrally as the court did in *Hibbing Taconite and Minnegasco.*

2. Consideration of Revenue Requirements

The standard for establishing just and reasonable rates is further defined by the Commission's differing authority with respect to different aspects of ratemaking. The Minnesota Supreme Court has recognized that the Commission's authority includes both quasi-judicial and quasi-legislative functions."[14] The Commission acts in a quasi-legislative capacity and has greater discretion with regard to rate design.[15] In contrast, the Commission is subject to the substantial evidence standard with respect to revenue issues.[16]

The distinction between the standards for revenue requirements and rate design is important here because a number of parties argue that the decision on several revenue issues should be influenced by fairness or on the basis that

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13 *Minnegasco v. Minnesota Public Utilities Commission*, 549 N.W.2d 904, 909 (Minn. 1996). ("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 ***.' §216B.16, subd. 6" (Emphasis by the Court.) Indeed, the dissent that specifically argued in favor of reading an overriding ratepayer protection into § 216B.03. (Gardebring, J. dissenting at 913). That position was rejected by the majority.

14 *See Hibbing Taconite Co. v. Minnesota Pub. Serv. Comm'n*, 302 N.W.2d 5, 9 (Minn. 1980). ("The single term "ratemaking" has been used to describe what is really two separate functions: (1) the establishment of a rate of return, which is a quasi-judicial function, and (2) the allocation of rates among various classes of utility customers, which is a legislative function. The court's failure to be more precise when discussing the two phases of ratemaking has led to the inappropriate statement that "ratemaking is a legislative process.")

15 *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n.*, 302 N.W.2d 5, 9 (Minn. 1980); *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n,* 312 Minn. 250, 260, 251 N.W.2d 350, 357 (Minn. 1977) ("Once revenue requirements have been determined, it remains to decide how, and from whom, the additional revenue is to be obtained .… The commission may then balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among customer classes … It is clear that when the commission acts in this area it is operating in a legislative capacity…").

16 *In re Request of Intestate Power Co. for Authority to Change its Rates for Gas Service*, 574 N.W.2d 408, 413 (Minn. 1998); establishing the standard of review for revenue requirement under the substantial evidence test; *Hibbing Taconite Co.*, 302 N.W.2d at 9 ("The *St. Paul Chamber* case enunciated the PSC's two functions and the related standards of review. In applying those standards, we now hold that the establishment of a rate of return involves a factual determination which the courts will review under the substantial evidence standard.").

shareholders also benefit from functions that are necessary to provide service. While the Commission may "draw its own inferences and arrive at its own conclusions" when reviewing the facts in the record,[17] there is no indication that recovery of the cost of furnishing service may be compromised on the basis of such non-cost factors.[18]

B. Burden of Proof

A number of parties correctly note in their briefs that Minn. Stat. § 216B.16, subd. 4, imposes the burden of proving "that the rate change is just and reasonable…" on the Company. However, many parties imply that this burden, combined with the substantial evidence test heightens the Company's obligations. The Department goes further to suggest that it, along with the intervening parties, does not even have a burden. This is incorrect. For context, the Company provides the following to clarify the appropriate burden of proof that the Company must meet.

The general rule is that "the burden of proof rests on the party seeking to benefit from a statutory provision."[19] This is echoed by the provisions of Minn. Stat. § 216B.16, subd. 4. In *Northern States Power Company for Authority to Change its Schedule of Rates for Electric Services*, the Minnesota Supreme Court described the utility's burden of proof as follows:

> In evaluating the validity of a rate increase application, the Commission should apply the classic burden of proof analysis employed in civil cases in determining whether the

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[17] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987).

[18] *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n,* 312 Minn. 250, 260, 251 N.W.2d 350, 357 (Minn. 1977); *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n*, 302 N.W.2d 5, 9 (Minn. 1980).

[19] *C.O. v. Doe*, 757 N.W. 2d 343, 352 (Minn. 2008); *Reliance Life Ins. Co. v. Burgess*, 112 F.2d 234, 238 (8th Cir. 1940) ("It is a fundamental rule that the burden of proof in its primary sense rests upon the party who, as determined by the pleadings, asserts that the affirmative of an issue and it remains there until the termination of the action. It is generally upon the party who will be defeated if no evidence related to the issue is given on either side.").

> utility has established the amount of a claimed cost as a judicial fact.[20]

The burden of proof in civil cases has two aspects, each of which is equally important: "the burden of persuasion and the burden of producing evidence."[21]

The burden of persuasion is "the duty of creating an affirmative belief on the part of the tribunal in the existence of the fact or facts in issue."[22] The burden of persuasion is generally fixed before the hearing and does not shift to the other party.[23] Here, the Company has the burden of persuasion, both as provided by Minn. Stat. § 216B.16, subd. 4, and under the general rule. 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."[24] This general rule applies both in administrative law proceedings and civil cases.[25] Consequently, a party must do more

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[20] 416 N.W.2d 710, 722 (Minn. 1987); *In re Interstate Power Co.*, 419 N.W.2d 803, 807 (Minn. Ct. App. 1988),

[21] Minnesota Practice, Vol. 11, Evidence § 301.01 (2013). *See also Schaffer ex re. Schaffer v. Weast*, 546 U.S. 49, 56 (2005) (determining which party bears the burden of proof in an administrative hearing); *Stockton East Water Dist. v. U.S.*, 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").

[22] 21 Dunnell Minn. Digest, Evidence § 13.01 (5th ed. 2006); *see Technology 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").

[23] Minnesota Practice, Vol. 11, Evidence § 301.01 (2013); Minn. R. Evid. 301 (2014) (presumptions shift "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 through the trial upon the party on whom it was originally cast."); *Commercial Molasses Corp. v. New York Tank Barge Corp.*, 314 U.S. 104, 110-11 (1941); *see e.g., Texas Dept. of Community Affairs v. Burdine*, 450 U.S. 248, 253 (1981) ("[t]he ultimate burden of persuading the trier of fact that the defendant intentionally discriminated against the plaintiff remains at all times with the plaintiff").

[24] 21 Dunnell Minn. Digest, Evidence § 13.03 (5th ed. 2006); *See also 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 a defendant, the plaintiff has met his burden of proof"); *Elk River Concrete Products Co. v. American Cas Co. of Reading, Pa.*, 129 N.W.2d 309, 314 (Minn. 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 (Minn. 1941) (finding that the "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 evidence to be expected of him").

[25] *E.g., Rydberg v. Goodno*, 689 N.W.2d 310, 313 (Minn. Ct. App. 2004) (applying the court's rule from *Fidelity Bank & Trust Co v. Fitzimons*, 261 N.W.2d 586, 590 (Minn. 1977) and finding that plaintiff had established a

than merely question if the Company has met its burden of persuasion. A party must instead rebut the Company's case with its own evidence for the Company's evidence to be called into question. The requirement to produce evidence is the burden of production.

The burden of production is "the duty of introducing evidence at a particular stage of a trial – of going forward with the evidence."[26] While the Company has the burden of proof, the burden of production may shift throughout a proceeding. The general rule is as follows:

> A prima facie case shifts to the opponent of the one having the burden of proof, the burden of producing evidence to overcome it.[27]

In Minnesota, the statutes and Rules set forth specific requirements for a complete rate application that details, supports and ties out revenues, costs and investments. That filing, coupled with its testimony and other evidence in support of the filing, constitutes substantial evidence, which establishes the Company's prima facie case. Any portion of the prima facie case that is unrebutted must prevail as a matter of law.[28]

By establishing its prima facie case, the burden of producing evidence (as opposed to mere argument, conjecture, or policy disagreement) shifts to the other

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prima facie case for pass-eligible status such that it was "unclear what more the commissioner [of human services] would have [plaintiff] prove," such that "at this point, the burden shifted to parties opposing pass-eligible status"); *In re Chicago Rys. Co.*, 175 F.2d 282, 281 (7th Cir. 1949) (finding that when a prima facie case is established by evidence and there is an "absence of explanatory or contradictory evidence" then "the finding shall be in accordance with the proof establishing the prima facie case").

[26] 21 Dunnell Minn. Digest, Evidence § 13.01 (5th ed. 2006). *See Technology Licensing Corp. v. Videotek, Inc.*, 545 F.3d 1316, 1327 (Fed. Cir. 2008); *Ryan v. Metropolitan Life Ins. Co.*, 298 N.W. 557, 560 (Minn. 1939) (discussing the differences between the burden of producing evidence and the burden of persuasion).

[27] 21 Dunnell Minn. Digest, Evidence § 13.03 (5th ed. 2006).

[28] *United States v. Ahrens*, 530 F.2d 781, 787 (8th Cir. 1976) (holding that the government satisfied its burden of proof to establish a prima facie case since the taxpayer failed to rebut the prima facie case, and therefore court was required to enter summary judgment in favor of the government).

parties.[29] If the prima facie case is rebutted with such evidence then the Company still has the burden of persuasion, but, again, to establish a rebuttal to the prima facie case, the other parties bear the burden of producing actual evidence. And, such evidence must be competent and probative.[30]

Here, the ultimate burden of proving the reasonableness of the proposed change in rates remains with the Company. But the burden of producing evidence to rebut the Company's initial case is on other parties. It is insufficient for a party to merely claim that the evidence is insufficient or to choose to claim the evidence is lacking due to the fact that the information was not audited. The parties may not appropriate for themselves the authority to judge when the Company's evidence is "sufficient" when this authority is vested instead with the Administrative Law Judge in the first instance, and ultimately with the Commission. Application of the appropriate standard to the record will result in just and reasonable rates.

C. Test Year Requirements

The Commission has articulated the standard to be applied in complying with this statutory requirement and setting just and reasonable rates for utilities:

> The ratemaking policy and practice adopted by the Commission is as follows. Rates that ratepayers currently pay are based on representative levels of revenue, costs, and investments in a "test year" determined at the time of the most recent rate case.[31]

Thus the test year is intended to be a "representative" level of revenues and costs. As the Commission has further explained:

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[29] *Texas Dept. of Community Affairs v. Burdine*, 450 U.S. 248, 252-56 (1981) (explaining that if the plaintiff establishes a prima facie case, then the burden of production shifts to the defendant to rebut the presumption raised by the prima facie case. If the defendant does not rebut the prima facie case and the plaintiff's evidence is believed by the trier of fact, then the court must enter judgment for the plaintiff).

[30] *LaFavor v. American National Insurance Company*, 155 N.W.2d 286, 291 (Minn. 1967) ("[w]hile the evidence in proof of a crucial fact may be circumstantial, it must not leave it in the field of conjecture).

[31] *In the Matter of the Complaint by Myer Shark et al, Regarding Xcel Energy's Income Taxes*, MPUC Docket No. C-03-1871, *Order Amending Docket Title and Dismissing Complaint* at p. 4 (Oct. 1, 2004)("*Shark Docket*").

> [T]he test year method … rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical – some favoring the Company, others not. Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year process. Anomalies are likely to exist in and beyond any test year. This rate-setting approach gives the utility an incentive to decrease costs between rate cases and protects customers from having to pay for every increase in costs between rate cases.[32]

The test-year concept is designed to enable the regulatory body to make an accurate prediction of revenues and expenses in the reasonably near future.[33] The Commission has previously articulated a symmetrical principle that should be applied to rate making and the test year.[34] The Company respectfully asks the Administrative Law Judge to consider the Company's requested rate increase in light of that principle.

III. KEY DISPUTED ISSUES

A. ROE

As explained in our Initial Brief, only the Company and Department have presented a ROE recommendation derived from methodologies accepted by the Commission. The Company's requested ROE of 10.25 percent establishes one end of the spectrum while the Department's recommended ROE of 9.64 percent establishes the other end. The Company has demonstrated that a 10.25 percent ROE would be appropriate, given the volatility of the market, the two-year period of the ROE decision in this case, and the scope of the Company's ongoing capital expenditures. The Company has also explained that a 9.64 percent ROE should not be accepted in this case because it fails to recognize prolonged financial market volatility, will result in the Company having an authorized return on equity more comparable to

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[32] *Shark Docket* at p. 4 (Oct. 1, 2004) (emphasis added).

[33] *See* Northwestern Bell Tel. Co. v. State, 253 N.W.2d 815, 822 (Minn. 1977).

[34] *Shark Docket* at p. 5 (Oct. 1, 2004).

distribution-only utilities and natural gas utilities than vertically integrated electric utilities, and will send a non-constructive signal to investors during a period of on-going capital investment.

With that said, the Company did discuss the possibility for the Commission to consider authorizing an ROE similar to the Company's currently authorized ROE of 9.83 percent. For context, the Company is presenting this as an option not only because it is similar to the Department's recommendation of 9.80 percent in direct testimony but as illustrative of the discretion we believe the Commission has in selecting an ROE that is in the range between 9.64 percent and 10.25 percent.

We believe the Commission should consider exercising this discretion due to the fact that this case, as a MYRP, presents a unique opportunity to deviate from traditional courses and consider other factors. Additionally, and more importantly, the Department's recommendation of 9.64 percent is only five basis points higher than the ROE recently authorized by the Commission for CenterPoint Energy. We do not believe it is reasonable for our authorized ROE to reflect the same risk profile as a natural gas only utility. This is especially the case when we are the largest utility in the state, operate nuclear generating units, and are responsible for a regional transmission system. Additionally, the fact that the Department's ROE analysis for CenterPoint is separated by six months from the analysis they performed on this record with similar results further supports the Commission exercising its discretion. Ultimately, the traditional ROE spread between a natural gas utility and vertically integrated electric utility seems more appropriate.

We believe the record can support an ROE that falls in the range between 9.64 percent and 10.25 percent. For example, the record can support an ROE of 9.77 percent, which is derived from an averaging method similar to the one used by the

Commission during its deliberations of the MERC natural gas rate case,[35] or 9.99 percent which is the average ROE authorized for other vertically integrated utilities since November 2012.

Thus, the Company, with this Reply, (1) continues to support its recommended ROE by diffusing the Department's criticisms of the Company's DCF analysis, (2) explain that a 9.64 percent ROE is incongruent with ROEs for other vertically integrated utilities, and (3) respond to the recommendations of the ICI Group and CG.

1. Evidence Supports the Company's Recommended ROE

Although the Commission has historically based its ROE determination on the Department's ROE recommendation, there is substantial evidentiary support for reflecting Mr. Hevert's Rebuttal DCF results in the determination of the ROE in this case, especially when so much of the difference between the Company and the Department relates to the time period used to perform the DCF analysis, and the ROE will remain in effect for two years.

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35 The Department's results from the 30-day periods reflected in its Direct and Surrebuttal recommendations are 9.80 percent and 9.64 percent respectively. The results from a 60 percent/40 percent weighting of the Company's DCF analysis for the 30-day period ending May 31, 2014 is 9.86 percent. The Company's results for the 30-day period ending May 31, 2014 using a 60 percent/40 percent weighting are as follows:*

	30-day DCF results	Weighting	Weighted Result
Revised Electric Proxy Group	9.97%	60%	5.98%
Revised Combination Proxy Group	9.70%	40%	3.88%
60/40 Weighted Result			9.86%

*Source Ex. 28, Hevert Rebuttal, Schedule 1, pages 1 and 4.

The average of the Department Direct and Surrebuttal recommendations and the comparable result from the Company's Rebuttal recommendation is as follows:

	Result
Department Direct	9.80%
Department Surrebuttal	9.64%
Company Rebuttal	9.86%
Total	29.30%
Divided by 3	3
Average	9.77%

The Department criticized the Company's DCF analysis for two main reasons: (1) using a time period longer than a single 30-day period;[36] and (2) applying an 80/20 percent weighting to the electric proxy group and combination proxy, rather than the 60/40 percent weightings applied by the Department.[37]

a. Not Appropriate or Necessary to use a 30-day Period

The Department has focused exclusively on a single 30-day period (June 7 to July 7, 2014). The Department selected a single 30-day period because of the "principle that financial markets are efficient such that the current stock prices fully reflect all publicly available information."[38]

But there is no need for the Commission to rely exclusively on data from a single 30-day period. Further, the current substantial instability of utility stocks[39] shows that no single 30-day period will be fairly representative of the cost of equity during the two-year term of the ROE in this case.

Other commissions, including FERC, traditionally look at price data from periods significantly longer than 30 days, and the Commission has recently recognized that unstable market conditions may justify looking at data from more than a single 30-day period to determine the ROE.[40]

For example, FERC uses a 6 month period to determine the dividend yield component, as shown in:

> For the dividend yield component of the DCF model, the Commission derives a single, average dividend yield based

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[36] Department Initial Brief at 25-26.

[37] Department Initial Brief at 26-28.

[38] Department Initial Brief at 26 (emphasis added).

[39] Ex. 115, Hevert Opening Statement at 2-3.

[40] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority To Increase Its Rates for Natural Gas Service In Minnesota*, G007,011/GR-10-977 (Deliberation September 25, 2014).

> on the indicated dividend and the average of the monthly high and low stock prices over a six-month period.[41]

The New York Public Service Commission had previously used a 6-month dividend yield, but more recently moved to a 3-month dividend yield saying:

> The judges' DCF calculations reflect common stock share prices for the three months ending November 30, 2008. They declined to rely on six months of data, and recommended we do the same at the time of our decision, … contrary to DPS Staff's and CPB's proposals.[42]

The New Mexico Public Regulation Commission has also used a range to dampen short term aberrations in stock prices:

> Using the range of ROEs determined by PNM's witness, Robert B. Hevert, using the 180-day trading period and full year dividend growth, results in a low ROE of 8.59%, a mean ROE of 10.72%, and a high ROE of 12.68%.[43]

The Commission has similar latitude to rely on more than a single 30-day period in this case.

Further, there is no basis to conclude that stock prices from the June 7 to July 7, 2014 period will be fairly representative of utility stock prices or the dividend yields and cost of equity for the two year term of the ROE decision in this case. The volatility of stock prices is clearly shown in the changes to dividend yields between the Company's Direct and Rebuttal DCF analyses and the Department's Direct and Surrebuttal DCF analyses.

The Department's FECG and FCCG dividend yields fell by 54 and 26 basis points, respectively, from Direct to Surrebuttal testimony. Similarly, the dividend

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[41] EL11-66-001, FERC OPINION 531 at 10 (June 19, 2014).

[42] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.* and *Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers*, Cases 08-E-0539 and 08-M-0618 at 121 (April 24, 2009).

[43] *Application of Public Service Company of New Mexico For A Revision Of Its Electric Service Rates*, Case No. 10-00086-UT, FINAL ORDER PARTIALLY APPROVING CERTIFICATION OF STIPULATION at 58 (July 28, 2011).

yields of the Company's Electric Proxy Group and Combination Proxy Group fell by 34 and 48 basis points, respectively, from Direct to Rebuttal testimony. Dividend yields decrease as stock prices increase, meaning that utility stock price increases in the early June to early July 2014 period drove the Department's dividend yields down and the decreased DCF results. The question is whether the 30-day stock prices relied upon by the Department will prove to be representative of the two-year period in which the ROE in this case will remain in effect.[44]

Utility stock prices have already moved below the prices prevailing in the June 7 to July 7 2014 period.[45] As a result, an ROE of 9.64 percent almost certainly does not reflect the current cost of utility stocks or the cost of equity and more changes can be expected during the two-year term of the ROE decision in this case. As a result, a 9.64 percent authorized ROE could be even more unattractive to potential investors six months or twelve months from now, especially in the context of the Company's ongoing inability to earn a reasonable return even with higher authorized ROEs.

If stock prices from a single 30-day period fully reflect the cost of equity, it is clear that we are in a period of extremely unstable costs of equity, as shown by the price changes described by Mr. Hevert and the resulting changes in the dividend yield.[46] That instability itself would support taking a more moderate approach to setting an authorized ROE that will remain in effect to the two-year term of the ROE decision in this case.

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[44] Ex. 115, Hevert Opening Statement at 2.

[45] Ex. 115, Hevert Opening Statement at 2 ("Since early July, we have seen the utility sector, including the companies used in our respective analyses, decline in process relative to relative to the broader stock market. … [T]he decline in utility stock valuations is consistent with the market expectation of increasing interest rates over the coming two years.")

[46] Ex. 115, Hevert Opening Statement at 2.

b. Weighting DCF results is Subjective

The Company recommended an 80 percent/20 percent weighting of the electric and combination company groups because the resulting 91.00 percent electric total weighted operations (based on relative operating income) is similar to the Company.[47] Further, the purpose of this proceeding is to set electric rates, which suggests that there should be no reflection of the lower costs of capital of gas operations (through the combination company data).[48] While Dr. Amit did not agree with the analysis, the Company's 80/20 approach, which has a reasonable basis that investors may take, should be rejected *only if* there is evidence that investors would not take this approach. There is no such evidence.

The Company agrees with the Department that selecting weighting factors reflect an element of subjective judgment, like a number of other decisions.[49] The Company and the Department do not disagree that the data from the combination companies provides some useful information and the Department and the Company agree that the electric comparable companies are more important, but differ as to their importance.

The Department criticizes Mr. Hevert's approach based on the assumption that the investment risks of the electric comparable companies and combination comparable companies are similar.[50] However, there are significant differences between the DCF results for the electric comparable companies and for the combination comparable companies which suggests that their investment risks may

[47] Ex. 27, Hevert Direct at 20.
[48] Ex. 27, Hevert Direct at 21.
[49] Ex. 400, Amit Direct at 43-44.
[50] Department Initial Brief at 27; Ex. 400, Amit Direct at 60.

not be similar. Specifically, the Company's updated DCF results for the Electric Proxy Group and the Combination Proxy Group show significant differences:[51]

	Electric Comparable Group	Combination Comparable Group	Difference
30 day Mean	9.97%	9.70%	27 bps
90 day Mean	10.02%	9.82%	20 bps
180 day Mean	10.13%	9.97%	16 bps

The results of the Department's original and updated DCF analyses show differences that are similar in scope:[52]

	FECG	FCCG	Difference
Direct Testimony 30 day Average	10.02%	9.47%	55 bps
Surrebuttal Testimony 30 day Average	9.72%	9.52%	20 bps

These differences suggest that the Electric Comparable Companies and the Combination Comparable Companies have significantly different investment risks that would be noted by investors.

Further, the both the Department's FECG and the Company's Electric Proxy Group contain proportions of both electric and natural gas distribution operations that are very similar to the Company's proportion of electric and natural gas distribution operations *without any weighting* being given the other groups of Combination utilities.[53] As such, an 80 percent/20 percent weighting is conservative and should not be disregarded in favor of sole reliance on an overly conservative 60 percent/40 percent weighting.[54]

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[51] Ex 28, Hevert Rebuttal at Schedule 1

[52] Ex. 400, Amit Direct at 37; Ex. 403, Amit Surrebuttal at 6.

[53] Ex. 28, Hevert Rebuttal at 18-21. The Department's FECG has 90.00 percent of net income from electric operations compared to the Company's 91.67 percent.

[54] Ex. 28, Hevert Rebuttal at 21.

The Department also relies on the fact that the all of the Company's electric and combination comparable companies are under the same Value Line and SIC code categories.[55] However, these very general classifications are not adequate to determine comparability. For example, the Value Line codes used by the Company established a universe of 48 electric companies and 59 combination companies[56] which were reduced to a final comparable group of 14 electric companies and 14 combination companies.[57] Such codes do not establish comparability for determining the cost of capital.

2. A 9.64 percent ROE would be significantly below the mainstream

Adopting the Department's recommendation ROE would put the Company's ROE into the bottom 20 percent of ROE awards for vertically integrated electric utilities (such as the Company) since August 2013 and would reflect ROEs more typical of gas distribution and electric distribution-only utilities. While the Commission does not set ROEs based on awards in other states, investors do compare awards between states and draw conclusions regarding the regulatory environment and the resulting business risks of those utilities.[58]

The Company presented all of the ROE awards for integrated electric utilities occurring between January, 2012 and May, 2014.[59] For a more recent period (beginning November 2013) the ROE awards for vertically integrated electric utilities were:[60]

State	Utility	Authorized ROE	Decision Date
WI	Wisconsin Public Service Corp.	10.20%	11/6/2013

[55] Department Initial Brief at 28; Ex. 400, Amit Direct at 61.

[56] Ex. 27, Hevert Direct at 22, 25.

[57] Ex. 27, Hevert Direct at 25, 27.

[58] Ex. 28, Hevert Rebuttal at 45.

[59] Ex. 28, Hevert Rebuttal at Schedule 13.

[60] Source: The table is a subpart of Ex. 28, Hevert Rebuttal Schedule 13).

State	Utility	Authorized ROE	Decision Date
KS	Westar Energy Inc.	10.00%	11/21/2013
VA	Virginia Electric & Power Co.	10.00%	11/26/2013
FL	Gulf Power Co.	10.25%	12/3/2013
WA	PacifiCorp	9.50%	12/4/2013
WI	Northern States Power Co - WI	10.20%	12/5/2013
OR	Portland General Electric Co.	9.75%	12/9/2013
LA	Entergy Gulf States LA LLC	9.95%	12/16/2013
LA	Entergy Louisiana LLC	9.95%	12/16/2013
NV	Sierra Pacific Power Co.	10.12%	12/16/2013
AZ	UNS Electric Inc.	9.50%	12/17/2013
GA	Georgia Power Co.	10.95%	12/17/2013
OR	PacifiCorp	9.80%	12/18/2013
MI	Upper Peninsula Power Co.	10.15%	12/19/2013
AR	Entergy Arkansas Inc.	9.30%	12/30/2013
ND	Northern States Power Co. - MN	9.75%	2/26/2014
NH	Liberty Utilities Granite St	9.55%	3/17/2014
NM	Southwestern Public Service Co	9.96%	3/26/2014
TX	Entergy Texas Inc.	9.80%	5/16/2014
	Average	**9.93%**	
	Median	**9.95%**	
	Minimum	**9.30%**	
	Maximum	**10.95%**	

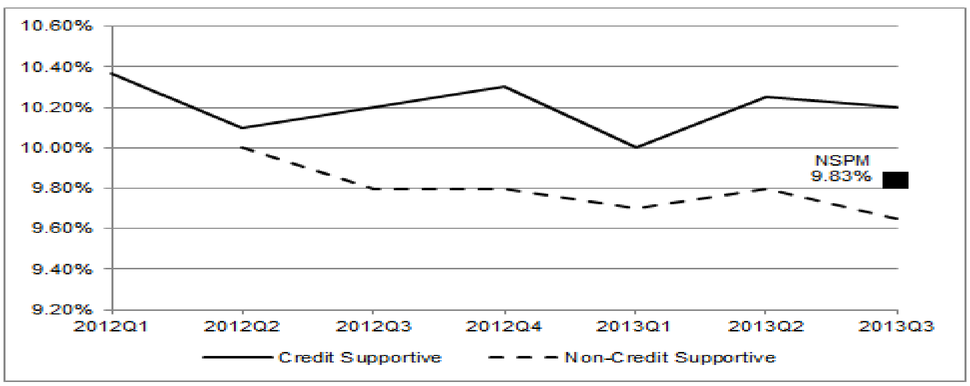
Only four of these 19 ROE awards were as low as, or lower than, the Department's recommended 9.64 percent ROE. The ROE awards for 51 vertically integrated electric utilities since November 2012 are very similar, with an average of 9.99 percent and a median of 10.00 percent.[61]

The ROE award in this case will send a communication to investors, which will be negative if the Department's ROE recommendation is adopted, and it is clear that investors are attuned to the regulatory environment in which the Company operates. S&P has noted:

[61] *See* Attachment A. (Source: Attachment A is a subpart of Ex. 28, Hevert Rebuttal Schedule 13).

> The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most.[62]

Minnesota has traditionally been regarded as credit supportive, but the current 9.83 percent ROE, much less the 9.64 percent ROE recommended by the Department are not keeping pace with ROEs from other credit supportive jurisdictions, as the location of 9.83 percent significantly below the solid line shows:[63]



Clearly, the Department's proposed ROE will place the Company's ROE at the bottom of the range of ROEs that utility investors see. For the period of August 2013 through May 2014, the Company's currently authorized ROE is in the bottom 39th percentile. Moving downward to 9.64% would put the Company in the bottom 10 percent of ROEs since 2012, and within the bottom 20 percent of returns authorized since August 2013.[64] This will be a significant negative signal in the context of a two-year plan and in the midst of ongoing very substantial capital

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[62] Ex. 27, Hevert Direct at 16 (quoting Standard & Poor's, *Utilities: Assessing U.S. Utility Regulatory Environments*, updated November 15, 2011).

[63] Ex. 27, Hevert Direct at 18

[64] Ex. 115, Hevert Opening Statement at 4.

expenditures. Because it would be the second successive ROE decrease, and would represent a return near industry lows, the 16 basis point difference between 9.80% and 9.64 percent would have a disproportionately negative effect.[65]

3. No Adjustment to the Department or the Company's recommendations is warranted.

As explained in our Initial Brief, none of the comments by AARP, the ICI Group, or Commercial Group would justify any adjustment to the ROE recommendations of the Department or the Company.

AARP continues to recommend that acceptance of a decoupling mechanism should lead to a reduction in ROE.[66] To the contrary, AARP's analysis fails to recognize that: (1) ROE is determined by the comparative risk of the Company in relation to its comparable companies (not on the basis of the Company is isolation; (2) there is no basis to believe that the decoupling leads to any noticeable reduction in relative risk; and (3) the Company's comparable companies also have comparable revenue mitigation mechanisms.[67]

The ICI Group complains that Dr. Amit and Mr. Hevert exercised professional judgment in deciding which DCF results met the threshold level of credibility that any investor would exercise when making an investment decision.[68] The ICI Group's citation to Dr. Amit's comment (that shareholders are not irrational to hold utilities with DCF results of under 8.0 percent) ignores Dr. Amit's (and Mr. Hevert's) point which is that when the results *of a model* are obviously not reasonable, those results should not be included in an analysis of what reasonable investors will rely upon. It is the results of the model that are not reliable, as Dr. Amit explained.[69] Instead of Dr.

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[65] Ex. 115, Hevert Opening Statement at 4
[66] AARP Initial Brief at 14-16.
[67] Ex. 28, Hevert Rebuttal at 48-54.
[68] ICI Group Initial Brief at 13-14.
[69] Tr. Vol. 4 Page 41 (Amit):

Amit's and Mr. Hevert's detailed analysis, the ICI Group also recommends, with almost no discussion, that the Commission should rely on Mr. Glahn's "well-reasoned DCF analysis."[70]

Rather, when the results of the DCF model did not make sense when compared to empirical information and do not pass a check of reasonableness, those results should thus be excluded, as Dr. Amit explained.[71] The fact that investors hold stocks in companies with unreasonably low DCF results does not mean that investors would actually accept the return shown by the DCF model.[72] It simply means that investors know that those DCF results are not representative. Instead of Dr. Amit's and Mr. Hevert's detailed analysis, the ICI Group also recommends, with almost no discussion, that the Commission should rely on Mr. Glahn's "well-reasoned DCF analysis."[73]

> "If the DCF analyses are less than 8 percent that does not mean that the cost of equity of the required rate of return by the investor is indeed what the DCF produce. The DCF is a theoretical way that is applied to try to estimate the cost of equity. Now there may be many issues with any specific one estimate for any company that may produce unreasonable results."

[70] ICI Group Initial Brief at 14.

[71] Tr. Vol. 4 Page 41 (Amit):

> "If the DCF analyses are less than 8 percent that does not mean that the cost of equity of the required rate of return by the investor is indeed what the DCF produce. The DCF is a theoretical way that is applied to try to estimate the cost of equity. Now there may be many issues with any specific one estimate for any company that may produce unreasonable results."

Tr. Vol. 4 Pages 45-46 (Amit):

> "The result has to basically – a good model is a model that when it's all said and done you get results that make sense when you compare it to empirical studies. So, basically, just because the DCF is a model to estimate the required rate of return, the outcome not necessarily makes sense sometimes. So you need to use other criteria to see – to basically check the reasonableness of your estimated DCF result."

[72] Tr. Vol. 4, Pages 40-41 (Amit):

> "[T]he fact that they buy shares has nothing to do with our estimated DCF ROE. In fact, there are two things. IF the DCF analyses are less than 8 percent, that does not mean that the cost of equity of the required rate of return by investor is indeed what the DCF produce."

[73] ICI Group Initial Brief at 14.

The Commercial Group relies entirely on ROE decisions from other jurisdictions, its extrapolations comparing Mr. Hevert's recommendations in other jurisdictions to the decisions in those jurisdictions, and a discussion of long-standing Commission policies on ROEs.[74] Significantly, none of this discussion (other than comparison to ROEs in other jurisdictions) was based on the testimony of its own witness. As explained in subsection 2 above, the ROE awards in other jurisdictions show that a reduction in the current 9.83 percent ROE would move the Company's Minnesota jurisdictional ROE into the bottom levels of recently awarded ROEs.

B. Monticello LCM/EPU

The Monticello LCM/EPU project is used and useful and it is therefore appropriate to include the project in rate base in its entirety. With the receipt of all necessary NRC licenses amendments to operate at EPU levels, the LCM/EPU should be viewed as the unitary project that it is, comprised of common plant utilized for both life cycle management and extended power uprate purposes. The completion of the ascension process is not a prerequisite to in-servicing the LCM/EPU and it should be expected that less than full performance of the plant would occur at this time as systems are shaken down and validated. This should not impact the used and useful determination.

At the outset, we note that intervening parties may be questioning why the Company continues to insist that the LCM/EPU project is used and useful when the plant is not operating at full uprate capabilities. The primary reason we continue to advance in this direction is our belief that our interpretation of the used and useful standard, including relevant legal precedent applied to the facts on this record, is reasonable and supports our position. As we explained in our initial brief and here, the uncontroverted facts on the record demonstrate that all of the capital for this

[74] Commercial Group Post Hearing Brief at 2-9.

program has been expended, and the plant, including those modifications installed as part of the LCM/EPU program, have been in the public use (i.e., serving our customers) during the test year. Since this is the appropriate litmus test, instead of an operational based one, we therefore believe the balance of the program should be placed into rate base at the start of the test year.

The Department of Commerce, XLI and CG primarily argue that full ascension of the plant to 671 MWe is the necessary prerequisite for satisfying the used and useful standard. We respectfully disagree. This is because achieving the full capabilities of plant investments, such as new transmission lines, fossil generating units or renewable generating units, is not always a binary proposition. There can be shakedown issues, changes in demand, or reliability considerations that limit operation. As a result, an operational based governor is not widely deployed and should not be here.

The Company recognizes that there is an appeal to limiting the amount our customers pay for this project until full ascension is achieved. While the Company believes fully restricting its recovery fails to account for the Company's financial undertaking in delivering the LCM/EPU project to our customers, we can understand a path that moderates the rate affect for public policy reasons. For this reason, the Company supports the Chamber's proposal with respect to the appropriate rate treatment of the Monticello LCM/EPU project in this case. The Chamber's proposal *recognizes* that the Monticello LCM/EPU project is used and useful while accounting for the fact that customers are not yet receiving the maximum benefits of the project. Therefore, the Chamber's proposal should be accepted.

Even though the Company has accepted the Chamber's proposal, which does not turn on whether the LCM/EPU program is legally used and useful, other parties have not. As a result, we first reply to the contentions of the Department, XLI and

CG that the program is not used and useful. We then respond to arguments that the Chamber's proposal is not in the public interest.

1. Used and Useful Standard is Met

Before exploring the legal intricacies of the used and useful standard to respond to several intervening parties, we believe there is a key factual difference between this case and the last, which supports finding the project to be used and useful. While we recognize the ALJ may reach a different conclusion as to what her words mean, we interpret her findings of fact to state that the lack of the EPU license amendments was the key barrier to finding the project to be used and useful:

> The EPU portion of the project is not "in service" <u>because the Company does not yet have the NRC license amendment required to operate at uprated EPU level</u>. As a result, the Company cannot generate the additional 71 MW that the EPU is designed to provide. The Company can only operate at its current licensed capacity. The Company will not be able [to] operate at its uprated power level until it receives authorization from the NRC.[75]

If the Company's interpretation is correct, namely that the lack of the license amendment was the key impediment to finding the Monticello LCM/EPU project used and useful, it then follows that failure to obtain the license amendment in the last case caused the Company to fail to meet the other milestones of the ALJ's application of the used and useful standard to the project:

> The fact that the project investments are being used to generate electricity at current levels for LCM purposes does not mean the entire LCM/EPU project is "in service" or "used and useful" for purposes of Minn. Stat. § 216[B], subd. 6. Because the plant is only generating power at existing levels, the EPU portion of the project is not "in service" or "used and useful." Any other interpretation of

[75] *In the Matters of the Application of the Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION at ¶ 79, Docket No. E-002/GR-12-961(July 3, 2013) (emphasis added).

> Minn. Stat. § 216B.16 would improperly allow the Company to recover EPU costs, with a return, before ratepayers ever receive the benefits of the additional 71 MW of EPU capacity. To allow recovery of the EPU costs before the plant provides the additional power would result in unreasonable rates for ratepayers.[76]

Reflecting on that record, we believe this decision to be consistent with the used and useful standard since there was a known impediment which would have made it impossible for the entire plant to be available for public use during the 2013 test year. This record, on the other hand, supports a finding of used and useful. The uncontroverted evidence on the record demonstrates that the Company is in receipt of all license amendments necessary for the operation at the plant at EPU levels.[77] The Company is "currently operating under an amended license that allows us to operate up to 2004 MWt (approximately 671 MWe)."[78] With the receipt of the required license amendments, the Company has begun the ascension process toward achieving the full 71 MW of uprated generation, and has achieved an additional 40 MW.[79]

Furthermore, "[t]he LCM/EPU Project is a unified Project that was not independently developed as separate LCM and EPU components."[80] The receipt of the license amendments allows for the Monticello LCM/EPU project to be viewed as a unitary project with common plant. "[A]ll equipment on the site is currently in place, being used to support ongoing plant operations and providing our customers

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[76] *In the Matters of the Application of the Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION at ¶¶ 81-82, Docket No. E-002/GR-12-961(July 3, 2013).

[77] Ex. 53, O'Connor Rebuttal at pp. 4-5.

[78] Ex. 53, O'Connor Rebuttal at p. 5.

[79] Ex. 53., O'Connor Rebuttal at p. 5.

[80] Ex. 53, O'Connor Rebuttal at p. 15.

with baseload, carbon-free energy."[81] And receipt of the license amendments provides the authority to operate the Monticello plant as an integrated whole at uprated levels, subject to NRC oversight and our license conditions.

The Company has also provided uprated generation to its customers. As noted, the Company began the ascension process, providing uprated levels of generation and 640 MWe of output for a sustained period of time.[82] And, while the ascension process is underway, the Company has "gained some efficiencies with some of the equipment that's already been replaced as part of the lifecycle management EPU; and we're operating a little bit better, in terms of total output, now that those modifications have been completed."[83] "Today, the plant is achieving over 90% of its potential [and] [i]t has already reached 95% of its potential safely…."[84]

Because the hurdles identified as part of our last rate case have been overcome, and the Company is providing, and our customers are receiving, the benefits of the Monticello LCM/EPU project, the Monticello LCM/EPU project is used and useful.

2. The Standard is not "Fully" Used and Useful

Several parties to this proceeding argue that Monticello must fully ascend and provide all 71 MW of uprated capacity before the project can be considered used and useful. This would substitute the used and useful standard for a more restrictive "fully" used and useful standard. This is contrary to the gatekeeping function of the used and useful standard and should not be adopted by the Commission and ALJ.

By way of background, rate regulation is based on the concept that a utility is dedicating its property for the public service:

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[81] Ex. 53, O'Connor Rebuttal at p. 14.

[82] Tr. Vol. 1 at p. p. 231 (O'Connor) (noting that sustained operation at 640 MWe occurred for "about 20 days").

[83] Tr. Vol. 1 at p. 245 (O'Connor).

[84] Ex. 53, O'Connor Rebuttal at p. 15.

> The investor agrees, by embarking capital in a utility, that its charges to the public shall be reasonable. His company is the substitute for the state in the performance of the public service, thus becoming a public servant. The compensation which the Constitution guarantees an opportunity to earn is the reasonable cost of conducting the business.[85]

When viewed in this context, the "used and useful" standard provides a gatekeeping function to determine what property the utility has dedicated to the public use and therefore, for which property the utility has a right on which to earn a reasonable rate of return:

> As of right safeguarded by the due process clause of the Fifth Amendment, appellant is entitled to rates, not per se excessive and extortionate, sufficient to yield a reasonable rate of return upon the value of property used, at the time it is being used, to render the services [to the public]. But it is not entitled to have included any property not used and useful for that purpose.[86]

Property is considered used and useful when it is dedicated to the public use for the purposes intended:

> These facts are not in substantial conflict with the Secretary's findings, and may be taken as established by the evidence. But they are not sufficient to prove that the property excluded is used and useful for the performance of services covered by rates being regulated by the Secretary.[87]

To perform this gatekeeping function, the Minnesota Supreme Court has found that property is "used and useful," when: (1) the property [will be] 'in service;' and (2) it [will be] reasonably necessary to the efficient and reliable provision of utility

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[85] *State of Missouri ex. Rel. Southwestern Bell Telephone Company v. Public Service Commission of Missouri et. al.*, 262 U.S. 276, 290-291 (1923) (Brandies, J. concurring).

[86] *Denver Union Stock Yard Company v. US*, 304 U.S. 470, 475 (1938) (citations omitted).

[87] *Denver Union Stock Yard Company v. US*, 304 U.S. 470, 476 (1938) (citations omitted).

service."[88] However, it is worth noting that "[t]he thing devoted by the investor to the public use is not specific property, tangible and intangible, but capital embarked in the enterprise."[89]

For this reason, other jurisdictions have not required full operation before finding the plant to be used and useful. For example, the Colorado Public Utilities Commission has found that all capital dedicated to a transmission line built at 345 kV but operated at 230 kV was used and useful and therefore appropriate to include in rate base.[90] The same is fundamentally true for power plants. "A power plant can be 'used and useful' without operating at full capacity."[91]

The arguments advanced by the Department, XLI and CG reveal a fundamental misunderstanding of the used and useful standard. Contrary to their assertions, the used and useful standard does not require the entire plant to be fully operational before it can be found used and useful. As a result, the Company respectfully requests the Commission and ALJ to reject their respective recommendations.

In addition to arguing for an operational governor, the Department advances several other arguments, which essentially raise the bar on the used and useful standard.

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88 *Senior Citizens Coalition v. Minnesota Public Utilities Commission*, 355 N.W.2d 295, 300 (Minn. 1984).

89 *State of Missouri ex. Rel. Southwestern Bell Telephone Company v. Public Service Commission of Missouri et. al.*, 262 U.S. 276, 290-291 (1923) (Brandies, J. concurring).

90 *In the Matter of the Application Of Public Service Company of Colorado for a Certificate of Public Convenience and Necessity for the Comanche-Daniels Park 345 kV Transmission Project*, INTERIM ORDER PARTIALLY GRANTING EXCEPTION AND REMANDING MATTER TO ADMINISTRATIVE LAW JUDGE at ¶¶ 7-10, Proceeding Nos. 05A-072E, C06-0094-I (January 25, 2006).

91 *State ex. rel. Utilities Commission v. Conservation Council of North Carolina*, 307 S.E.2d 375, 378 (N.C. App. 1983) (finding McGuire Unit One used and useful because "over 279,000,000 kWh had been produced by McGuire Unit One; it was operating well at 50% rated capacity; and Duke expected to increase capacity without problems or delays"); *see also Office of Consumers' Counsel v. Public Utilities Commission*, 391 N.E.2d 311 (Ohio 1979) (finding nuclear generator not used and useful during initial ascension testing due to, among other things, failure of plant to provide any energy to transmission system net of its own power consumption).

First, the Department believes the Company has not met its burden of proof to demonstrate that the project is used and useful.[92] The Company respectfully disagrees and points to initial brief and the prior sections of this Reply Brief as illustrative.

Second, the Department relies on a few facts to imply the Company has acted imprudently with respect to the LCM/EPU project. For example, the Department notes the NRC required the Company to power-down the Monticello plant to pre-EPU levels due to human performance errors.[93] Not only is this factually incorrect,[94] but the logical extension of their argument is the Company should be financially penalized for conservatively operating a nuclear generating plant consistent with industry expectations.

Nuclear generators are one of the most complex machines in existence and "both the Company and our regulators want to ensure the safe and reliable operation of this … generation facility, which is why this testing is being performed."[95] Given this complexity, "the license for the site is written such that the NRC expects plants to experience anomalies during the ascension process and specifies how the operator is supposed to conduct reporting and triage of those issues. Finding anomalies during ascension is not unique to Monticello."[96] In fact, this is not unique to nuclear power plants. "Typically fossil plants would [also] perform testing to assure that they verify the expected power uprate as well as perform testing on the new equipment to understand performance characteristics of the equipment at the new power level."[97] It would be not be sound public policy to use safe operating practices as a basis to find the project is not used and useful.

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[92] Department Initial Brief at pp. 77-79.

[93] Department Initial Brief at p. 81.

[94] Ex. 53, O'Connor Rebuttal at p. 10.

[95] Ex. 53, O'Connor Rebuttal at p. 7.

[96] Ex. 53, O'Connor Rebuttal at p. 8.

[97] Ex. 53, O'Connor Rebuttal at p. 7.

Furthermore, the Department is really raising questions of prudent project management and not one related to determining whether the plant is used and useful. In fact, the Department is using these same facts, among others, to support their downward adjustment in the separate prudence investigation proceeding.

The Monticello LCM/EPU is operating better, more safely, and more efficiently than before the Program; has ascended partially; and is continuously using all equipment that was part of the LCM/EPU Program. Thus the Monticello LCM/EPU has met both the accounting standard and the standard from the prior case, and should be considered in service.[98] In addition to the reasons articulated in the prior section, the entirety of the Company's capital for the LCM/EPU project is being utilized in furtherance of the public service. As a result, the project is used and useful and should be included in rate base consistent with these concepts.[99]

3. Proposed Resolution

In light of the above discussion, the remaining issue is, what, if any, impact does the fact that the Monticello LCM/EPU has not fully ascended to its full 671 MW output have for ratemaking purposes. The appropriate application of the used and useful standard would argue that the answer is none. If the gatekeeping function of the used and useful standard is met, the Company has expended its capital on the project and since the project is now dedicated to the public use, the Company should earn a return on its capital. If the capital was prudently invested is a determination outside of this proceeding and not part of application of the used and useful standard. However, the Chamber's proposal for the treatment of Monticello costs provides a reasonable middle ground with respect to the fact that the Monticello Plant is used

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[98] Ex. 94, Perkett Rebuttal at p. 45.

[99] At minimum, the Company has demonstrated that 40/71 MW of the uprated capacity has been generated and therefore capital related to at least 40/71 of the EPU project has been used and useful for service to the Company's customers.

and useful but has not operated at 671 MW consistent with the reasonable expectation of the parties. As the MCC provides:

> The Chamber's recommendation is that Xcel be permitted to leave the EPU in rate base, but remove depreciation expense and recover it over the remaining life of the plant. The Chamber also recommended that the increased fuel costs as a result of Xcel's inability to demonstrate the EPU goal of 671 MW during the test year be returned to ratepayers and collected from ratepayers over the remaining life of the plant. The reasoning behind the adjustment is that collection of increased fuel costs <u>and</u> allowing a plant in rate base, effectively would result in ratepayers paying twice for the power used (through cost included in rate base and again through the FCA). The increased cost of fuel is a risk and cost of construction and like any other costs incurred during construction, it should be accumulated and recovered from ratepayers that benefit from the plant during its useful life.[100]

The Chamber's proposal reasonably reflects that the Monticello LCM/EPU project is used and useful but has not yet operated at full uprate capacity. To do this, the Chamber's proposal allows the Commission to make its used and useful gatekeeping determination while deferring the costs of operating the plant and the costs of its current operations at less than full EPU levels to those customers who will receive the benefits. The Company concurs with the Chamber that this provides a reasonable middle ground on a policy basis and is consistent with general ratemaking principles.

The Department's concerns with the Chamber's proposal do not withstand closer scrutiny. First, the Company has shown that the Monticello LCM/EPU is used and useful and therefore, the initial gatekeeping requirement established by the Department has been met. Second, the Chamber's proposal is consistent with the

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[100] MCC Initial Brief at pp. 4-5 (emphasis in original) (citations omitted).

Commission's treatment of certain costs of other generation facilities that were idled during the test year,[101] the Department's assertions to the contrary notwithstanding.

Finally, the Chamber's proposal appropriately meets the "task at hand [which] is to equitably balance the interests of the ratepayers and shareholders regarding" the Monticello LCM/EPU.[102] The Chamber's proposal is not backwards, as the Department contends,[103] but rather appropriately balances the interests of ratepayers and the Company: the Company earns a return on its capital dedicated to the public use and ratepayers are not paying the costs imposed by the anomalies encountered during the ascension process. Therefore, the Chamber's proposal should be accepted.

C. Passage of Time

Even though the record is clear that the passage of time adjustment will increase the Company's 2015 revenue requirement, the Department continues to advocate for an approximately $17.5 million downward passage of time adjustment. The only place in the record where the approximately $17.5 million amount that supports the Department's adjustment can be found is in an incomplete response from the Company to a Department information request.

In its Initial Brief, the Company discussed why it opposes the Department's proposed passage of time adjustment. Logically, a passage of time adjustment is not necessary since depreciation expense will outpace rate base additions in 2015. From a policy perspective, the passage of time adjustment discourages the use of the innovative MYRP construct established by the Commission as it seeks to lower the

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[101] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-916, FINDINGS OF FACT, CONCLUSIONS AND ORDER at p. 23 (September 3, 2013) (allowing the deferral of depreciation expense for Sherco 3 during its extended outage).

[102] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-916, FINDINGS OF FACT, CONCLUSIONS AND ORDER at p. 22 (September 3, 2013) (setting the appropriate policy standard with respect to costs for Sherco 3 during its extended outage).

[103] Department Initial Brief at p. 92.

out-year revenue requirements while not allowing full adjustments to the cost of service outside of limited capital additions. Lastly, if the proposed passage of time adjustment was accepted, it should be calculated correctly, which results in an increase to the Company's 2015 revenue requirement of either $1.9 million in a perfectly symmetrical calculation (*i.e.*. annualization of all 2014 projects into the 2015 Step) or $950,000 for a properly calculated passage of time adjustment as proposed by the Department.

In its initial brief, the Department now argues that the passage of time adjustment can be calculated by only looking at the change in accumulated depreciation reserve (rate base), and is warranted because the Department never audited the Company's full revenue deficiency for 2015 and as a result the record does not allow a passage of time adjustment calculated symmetrically to consider both the change to accumulated depreciation reserve and depreciation expense.

These new arguments do nothing more than illustrate an unwillingness to accept that a passage of time adjustment is not appropriate in this case. For the reasons articulated below, as well as in our initial brief, the Company respectfully requests the Department's passage of time adjustment be rejected.

1. The Department's Evolving Methodology

In its initial brief, the Department now explains that only changes to accumulated depreciation reserve need to be factored into a passage of time adjustment. Specifically, "Ms. Campbell determined that it was not necessary to update depreciation [expense] for the passage of time for [the non-2015 Step] capital projects were in service by the end of 2014…."[104] This was because the Company's 2015 Step accounted for the revenue requirements of 81.3 percent of the Company's

[104] Department Initial Brief at p. 233.

total increase in 2015 rate base.[105] In other words, the Department is limiting its passage of time adjustment to just the rolling forward of accumulated depreciation for all of the Company's 2014 rate base and is disregarding the step-up in depreciation expense for all of the 2014 rate base into 2015 because the Company's proposed 2015 Step revenue requirement already accounted for most of the step up in depreciation expense.

The Department's new methodology is contrary to the underlying theory behind the passage of time adjustment, which is that, due to the passage of time, the Company's 2015 revenue requirements should be reduced by updating the entirety of the Company's 2014 rate base in 2015 to reflect accumulated depreciation and depreciation expense for the out-years of the Company's MYRP.[106]

The Department's new approach is also a sharp deviation from the theory it espoused in pre-filed testimony and testimony at the evidentiary hearing. For example, the Department has stated the following:

> I note that it is appropriate to reflect depreciation expenses and related accumulated depreciation for the passage or time….[107]
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> I consider it inequitable to allow the Company to add $68.865 million in plant additions … without reflecting reduced depreciation expense and related accumulated depreciation for existing plant in rate base for the passage of time….[108]
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[105] *See* Department Initial Brief at p. 233; Ex. 435, Campbell Surrebuttal at p. 119.

[106] Tr. Vol 5 at p. 52 (Campbell) ("I would look at the incremental increase in depreciation expense, if there was one, and I would look at the stepdown in accumulated depreciation, if there was one, in calculating the passage of time").

[107] Ex. 429, Campbell Direct at 158 (emphasis added); *see also* Campbell Direct at 162, 164.

[108] Ex. 429, Campbell Direct at 158 (emphasis added).

> I note that it is necessary to make the adjustment for the passage of time (from 2014 to 2015) step down in rate base by recording depreciation expense <u>and</u> accumulated depreciation reserve….[109]
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> ***
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> I would look at the incremental increase in depreciation expense, if there was one, and I would look at the stepdown in accumulated depreciation, if there was one, in calculating the passage of time.[110]

In fact, to establish the passage of time adjustment, the Department requested that the Company provide "the rate base, income statement and revenue requirement effect of updating depreciation expense <u>and</u> accumulated depreciation reserve to reflect the passage of time for 2015 (except for the 2015 step projects already reflected in the 2015 step)."[111]

Furthermore, the Department's new methodology is egregiously asymmetrical. While the Department is correct for projects that have been in-service for more than a year, where the full annual depreciation expense for that project is included in base rates, for those projects that were placed in-service for only a partial year when base rates were calculated (*i.e.*, those projects placed in-service in 2014) only a partial year's depreciation and depreciation expense is captured in the 2014 revenue requirement. Consequently, to account for the passage of time by calculating rate base to reflect a full year of depreciation for all of those projects placed in-service in 2014, there must be a corresponding update in base rates for a full year of depreciation expense for those same projects to maintain the symmetry of the calculation. If a corresponding update to the depreciation expense is <u>not</u> made, as suggested by the Department now, the passage of time adjustment would decrease the Company's rate base without the

[109] Ex. 435, Campbell Surrebuttal at 114 (emphasis added).
[110] Tr. Vol 5 at 52 (Campbell).
[111] Ex. 430, Campbell Direct at Schedule NAC-32 (emphasis added).

corresponding expense included in rates (increasing base rates). Contrary to their assertion that they did not audit the full 2015 revenue requirement, the depreciation expense adjustment that creates symmetry relates to the 2014 in-service assets that were fully reviewed by the Department.

In this case, where the 2015 Step has been limited to certain capital projects and associated O&M, the Department's new theory justifying the $17.5 million passage of time adjustment should be rejected. If considered at all, the passage of time adjustment should be analyzed symmetrically by giving consideration to both changes in accumulated depreciation reserve and depreciation expense. When this is done, as the Company demonstrated in the Rebuttal Testimony of Ms. Lisa Perkett, one will see that the Company's depreciation expense is growing more quickly than the additions to rate base in 2015 and, therefore, accounting for the passage of time results in an increase to the Company's 2015 revenue requirement, not a decrease.[112]

2. What the Record Allows…

To support its asymmetrical application of the passage of time adjustment, the Department claims that the total increased depreciation expense in 2015 was not included in the Company's 2015 Step request and should therefore be disregarded.[113] The Department is essentially claiming that it need only carry forward the increase in depreciation reserve and disregard the increase in depreciation expense because the Company limited its 2015 Step request.

Contrary to the Department's assertion, the Company did inform the record with the information necessary to symmetrically calculate the passage of time adjustment. This includes the approximately $17.5 million stepdown in accumulated

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[112] *See* Ex. 94, Perkett Rebuttal at Schedule 2, page 5.

[113] Ex. 435, Campbell Surrebuttal at p. 115 ("I am concerned that the Company is treating its assertion that $713.4 million in the amount of the increase in rate base for the full 2015 forecast as if this amount had been subject to examination – it has not, since the Company did not request recovery of this amount in this rate proceeding."); *see* Department Initial Brief at 236 ("if Xcel has actually asked in its initial rate case petition for recovery of the full 2015 revenue deficiency").

depreciation reserve, which is uncontested in this proceeding, and the approximately $18.4 million increase in depreciation expense, which is also uncontested in this proceeding.[114]

Rather than apply the information in the record to its passage of time adjustment, the Department chose to disregard it as incompatible with its $17.5 million calculation. The Department is ignoring this record evidence because it "has not been examined or audited for accuracy or reasonableness."[115]

The Company is troubled by this argument. Not only does such an argument undermine the policy limitations outlined in the Commission's MYRP Order, but the Company provided its 2015 cost of service as part of its initial filing in November 2013, and the revenue requirements associated with 2015 capital additions as part of rebuttal testimony in July 2014. Even though information relevant to vetting the Company's depreciation expense for 2015 has been available since the Company filed this case, no party chose to audit this information.

The Department's failure to audit this information does not mean that it should be disregarded; rather it means that is uncontroverted fact. Stated differently the Company met its burden of proof by presenting its 2015 revenue deficiency and cost of service.[116] This means that the burden of producing evidence to rebut the Company's *prima facie* case shifted to the Department.[117] The Department has affirmatively chosen not to do so. Consequently, the Company's depreciation expense for 2015 is an uncontroverted fact, which when used confirms that a passage of time adjustment is not needed in this case, or if made would result in an increase to the Company's 2015 revenue deficiency.

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[114] Ex. 94, Perkett Rebuttal at Schedule 2, page 5.

[115] Department Initial Brief at p. 232; *see, also* Ex. 435, Campbell Surrebuttal at p. 115 (explaining how the Department did not examine the record evidence);

[116] 21 Dunnell Minn. Digest, Evidece § 13.03.

[117] 21 Dunnell Minn. Digest, Evidece § 13.03.

3. The Company's Response to IR 2113

The Department's continuing advocacy for a $17.5 million passage of time adjustment is inherently asymmetrical as it only captures the increase in accumulated depreciation reserve from 2014 to 2015 without regard for the concomitant full increase in depreciation expense. As explained in the Company's Initial Brief, the Company provided an incorrect calculation in response to the Department's information request no. 2113 as it only provided the increase in depreciation reserve without providing the offsetting increase in depreciation expense in its response.[118] It is this error that is the basis for the Department's proposed $17.5 million adjustment. The Department was aware that the $17.5 million calculation provided by the Company was in error.[119] The Company's error is not a reasonable basis for an adjustment.

4. Conclusion

The Company continues to oppose the passage of time adjustment since the evidence on the record demonstrates that the Company's depreciation expense in 2015 outpaces its additions to rate base, thereby causing any adjustment to be an increase to the Company's revenue deficiency in 2015, and on policy grounds as discussed in its Initial Brief. However, should the ALJ choose to recommend this adjustment, it should do so based on the correct calculation of this adjustment as provided on the record which includes both reductions to rate base and increases in depreciation expense.

D. Pension and FAS 106 Expense – 2008 Market Loss

For decades, the Company has calculated its qualified pension expense consistent with the Aggregate Cost Method (ACM) and FAS 87, both of which

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[118] *See* Ex. 430, Campbell Direct at Schedule NAC-32 (only providing roll forward of accumulated depreciation reserve).

[119] *See* Department Initial Brief at p. 233.

incorporate prior-period gains and losses in the calculation of current year pension expense.[120] In this case, the Company calculated its test year pension expense in exactly the same way it did during the many years in which customers received the benefit of prior-period gains and losses. But because of the unprecedented market losses the Company's pension trusts experienced in 2008 (2008 Market Loss), the incorporation of prior-period gains and losses increases the test year pension expense, rather than decreasing it. As long as the method of incorporating prior-period gains and losses in the calculation of current-year pension expense was reducing pension expense and thereby benefiting customers, the Department had no objection. But now that the application of that very same methodology would increase test year pension expense (albeit by far less than the annual benefits customers have received in the past), the Department urges the Commission to exclude a portion of the prior-period losses. The Commission should reject this results-oriented approach.

1. 2008 Market Loss Test Year Calculation

In its initial brief, the Department noted that the Company has included the entire 2008 Market Loss in the calculation of the test year qualified pension expense.[121] However, as the Company explained in its initial brief, the 2008 Market Loss was phased in over a five-year period, and the phased-in amounts are being amortized over even longer periods.[122] So although the remaining net unamortized losses from 2008 total $95.5 million for the NSPM Plan, only $6.2 million is included in the test year qualified pension expense as a result of not only the phase-in and amortization, but also the offsets from other prior-period gains.[123] And of the $36.1 million of unamortized XES Plan losses remaining from the 2008 Market Loss, the

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[120] Ex. 83, Schrubbe Rebuttal at 21.

[121] *See, e.g.,* Department Initial Brief at 109 (stating that "Xcel requests recovery from ratepayers of 100 percent of this 2008 market loss").

[122] *See* Company Initial Brief at 57.

[123] Ex. 82, Moeller Direct at 29-30.

Company is seeking to include only $3.46 million in the test year qualified pension expense after the offsets from prior-period gains.[124] Thus, the Company is not seeking to include anywhere near "100 percent" of the 2008 Market Loss in test year qualified pension expense, as the Department alleges. Rather we are asking to include the consistent accounting treatment for all gains and losses that we have applied in prior years in order to recover all net gains and losses regardless of whether they increase or decrease the revenue requirement.

2. The Company managed its pension trust assets prudently

The Department next discusses Ms. Campbell's concerns that "Xcel did not show that it managed its pension assets reasonably given that Xcel is still asking ratepayers to pay $12 million in annual rates between now and its next rate case to reflect that market loss."[125] The Department elaborates on that concern by noting that despite "the financial market returning to levels above the pre-2008 market loss levels, Xcel's pension assets have not similarly recovered."[126] The Company's response to that "concern" is threefold.

First, as Mr. Tyson testified in his opening statement,[127] the Company's pension trust portfolio is highly diversified with holdings not only in equities, but also fixed income securities, real estate, and commodities.[128] And the equities portion – which is presumably what the Department is referring to when it states that the "financial market [has] return[ed] to levels above the pre-2008 market loss levels"[129] – earned a

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124 Ex. 82, Moeller Direct at 30.

125 Department Initial Brief at 109.

126 Department Initial Brief at 109.

127 Ex. 116, Tyson Opening Statement at 2-3. It was necessary for Mr. Tyson to offer this evidence in his opening statement because the Department waited until surrebuttal testimony to argue for the first time that the Company's handling of its pension asset trust portfolio justified the exclusion of part of the 2008 Market Loss.

128 Ms. Campbell admitted on cross that the trust fund assets are not limited to equities. Aug. 15 Tr. at 35-36.

129 Ms. Campbell confirmed on cross-examination that her reference to the market was intended to refer primarily to the U.S. equities markets. Aug. 15 Tr. at 35.

33.3 percent return in 2013.[130] That return is consistent with benchmarked returns for equities[131] and demonstrates that the Company has managed its equity assets in a way that captures market gains. Investment returns have been weakened due to fixed income investment underperformance, however, the same factors affecting fixed income returns have led to historically low debt issuance costs. As Mr. Moeller testified in Direct,[132] the Commission should not pick and choose between where impacts to the cost of service (debt interest expense) benefit our customers, where those same factors can cause higher costs (pension).

Second, to the extent the Department is arguing that the Company mismanaged its portfolio by having too much equity in it before the 2008 market downturn and too little afterward,[133] the argument should be rejected. It presumes that investors can foresee whether equities markets will go up or down, which is simply not possible. Although it is easy in hindsight to argue that the Company should have retained or even increased its equities holdings after 2008, the Company has a fiduciary duty in protecting the pension trust so that it is available today and for many years to come. Moreover, when asked on cross-examination what evidence the Department relied on to support the allegation that the Company's equities position was "overly optimistic" before 2008, Ms. Campbell had no relevant response.[134]

Third, the Department's argument that the recent market gains are not being fully reflected in the calculation of pension expense ignores the effects of the phase-in and amortization required under both the ACM and FAS 87. As discussed in detail in

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[130] Ex. 116, Tyson Opening Statement at 3. If the Department is instead arguing that *all* of the holdings in the pension trust portfolio have returned to their pre-2008 level, that is flatly wrong. The undisputed evidence demonstrates that returns for fixed-income securities are far lower than they were before 2008. *See, e.g.*, Ex. 83, Schrubbe Rebuttal at 45.

[131] Ex. 31, Tyson Rebuttal at Schedule 1, p. 2.

[132] Ex. 82, Moeller Direct at p. 10.

[133] Department Initial Brief at 108.

[134] Aug. 15 Tr. at 36. Ms. Campbell simply referred back to her "two reasons" discussed earlier, neither of which discussed the Company's equities position before 2008. *Id.* at 34-35.

the Company's testimony, asset gains and losses are phased in over a five-year period, and then the phased-in amount is amortized over a period of years. Thus, the gains achieved in 2012 and 2013 are still being phased in and amortized. Although customers might prefer that the phase-in and amortization dictated by the ACM and FAS 87 not delay the recognition of gains, customers benefited from the phase-in and amortization of losses after 2008.[135] As the Company noted in its initial brief, there cannot be one rule for gains and another for losses.

3. The Company's pension benefits are not excessive

The Department next argues that, although it "has agreed that a reasonable level of retirement benefits are a legitimate cost of service," the Company's request to include qualified pension expense in the cost of service is "troubling" because the cost of service also includes amounts used to match a portion of employees' 401(k) contributions.[136] But as the Company stated in its initial brief, third-party benchmarking evidence demonstrates that the Company's "retirement program for new hires ranks as one of the lowest among peer companies" and that the Company's "legacy retirement program would benchmark slightly lower than our peer companies median retirement programs."[137] The Company also offered evidence that the 5% Cash Balance program, which is the sole defined benefit retirement program available to newly hired employees, provides only an 8% income replacement level.[138] Ms. Campbell admitted on cross that she reviewed the specific and quantifiable testimony about the Company's level of benefits compared to peer companies,[139] but she offered no evidence to rebut that testimony in her surrebuttal testimony or in her opening

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[135] Ex. 82, Moeller Direct at 54 (explaining that $80.1 million of prior-period gains kept the recognition of pension expense attributable to the 2008 Market at zero until 2011).

[136] Department Initial Brief at 111.

[137] Ex. 78, Figoli Direct at 24-25.

[138] Ex. 82, Moeller Direct at 70-71; *see also id.* at 80 ("Without the qualified pension plan and 401(k) matching benefits, the Company would have to pay significantly higher current compensation to attract employees.").

[139] Aug. 15 Tr. at 39.

statement. Because the only factual evidence in the record demonstrates that the Company's benefits are not excessive, the Commission should reject the Department's argument.

4. Response to the Department's Remaining Arguments

The Department's initial brief advances several other arguments, none of which has any merit. For example, the Department reiterates that the Company does not treat gains and losses symmetrically in the calculation of pension expense because the gains or losses are not "given back to ratepayers," but instead are maintained "in the pension plan to offset future pension costs."[140] In fact, maintaining the gains and losses in the pension trust fund does constitute symmetrical treatment because the negative pension expense arising from gains is not available to either the Company (*i.e.*, shareholders) or to customers. All of the gains remain in the pension trust fund and are used to reduce future pension expense, which ultimately benefits customers.

The Department also reiterated Ms. Campbell's disagreement with Mr. Moeller's statement that neither Company shareholders nor employees benefit when market gains exceed expectations.[141] According to Ms. Campbell, when the pension plan is overfunded, the Company does not have to make payments to the pension fund.[142] That is generally true, but when the opposite occurs (*i.e.,* the plan is underfunded and the utility must make contributions), those contributions are a reasonable cost of providing utility service, and therefore they are included in rates. Thus, the benefits of market gains that exceed expectations flow exclusively to customers, who pay less in pension expense. There is no benefit to the Company.

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[140] Department Initial Brief at 113; Ex. 435, *see also* Ex. 435, Campbell Surrebuttal, at 91.
[141] Department Initial Brief at 114.
[142] Ex. 435, Campbell Surrebuttal at 91-92.

Finally, the Department notes that pension expense will be $0 by 2017 or 2018.[143] Mr. Schrubbe testified that there will continue to be pension expense in 2017 and beyond because the Company has contributed substantially more to the pension trust fund than it has recognized in pension expense.[144] Although pension expense will drop somewhat in 2017 and 2018, it will not fall to $0 until the amounts contributed have been recognized as part of qualified pension expense.[145]

5. Two Alternative Proposals

The Company has shown that it is reasonable to use prior-period gains and losses in the calculation of qualified pension expense, and thus there is no need for the Commission to reduce or modify the Company's requested qualified pension expense.[146] But if the Commission believes that it would be appropriate to moderate the test year qualified pension expense in some way, the Company has presented two alternatives that could be used for that purpose, in addition to the continuation of the two mitigation mechanisms approved by the Commission in the Company's last rate case, Docket No. 12-961.[147]

The Company's first alternative proposal is a mechanism that compares a five-year average, normalized qualified pension expense to the Company's actual qualified pension expense each year, with the difference being deferred each year until the normalized amount is revised in 2017 or 2018, at which time the deferred amount will

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[143] Department Initial Brief at 110, 112.

[144] Ex. 83, Schrubbe Rebuttal at 26.

[145] Ex. 83, Schrubbe Rebuttal at 27 (showing that pension expense is forecasted to be $16.8 million in 2017 and $15.3 million in 2018).

[146] Ex. 83, Schrubbe Rebuttal at 30 (Mr. Schrubbe testifying that "the Company is not proposing alternative normalization mechanisms because the 2014 test year is un-representative of our qualified pension expense or because we are concerned our requested relief is unsupported in the record, or unreasonable").

[147] In Docket No. 12-961, the Commission approved the use of a longer amortization period to recover the phased-in portion of the 2008 Market Loss for the NSPM Plan. The Commission also approved a mitigation mechanism by which pension expense is capped at the 2011 level, with any excess deferred for later recovery. Ex. 83, Schrubbe Rebuttal at 34.

be amortized over a period of time approved by the Commission.[148] Under this proposal, the combined pension expense for the NSPM Plan and the XES Plan would be set at $18,246,925, which is the annual average of the forecasted pension expense for the five year period from January 1, 2014 through December 31, 2018.[149] The Company will track the difference between the five-year average and the Company's actuarially determined actual qualified pension expense for each year, and the balance will be recorded in a deferred account that is added to or subtracted from the Company's rate base.[150] Under this proposal, the amount would remain the same through the end of 2018, but the normalized qualified pension expense could be, and likely would be, reset in a future case that takes place near the end of the five-year period. As noted by Mr. Schrubbe, "[S]etting the pension expense for this period of time will provide certainty and stability in pension expense for a multi-year period and will allow the Commission and the parties to focus their resources on other issues."[151]

The Company's second alternative proposal would also use the five-year average from 2014 through 2018, which is $18,246,925, but instead of deferring the difference between the Company's actual pension expense and the normalized expense, the Company would defer the difference between the normalized amount and the lesser of: (1) the actual qualified pension expense each year, or (2) the currently forecasted pension expense for each year during the period 2014-2018.[152] Because the Company is proposing to use the lesser of the actual or forecasted

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[148] Ex. 83, Schrubbe Rebuttal at 31.
[149] Ex. 83, Schrubbe Rebuttal at 32.
[150] Ex. 83, Schrubbe Rebuttal at 32-33 (providing an example of how the first alternative proposal would work).
[151] Ex. 83, Schrubbe Rebuttal at 33-34.
[152] Ex. 83, Schrubbe Rebuttal at 35-36 (providing an example of how the mitigation mechanism would work).

expense, there could never be a deferred asset at the end of 2018, although there could be a deferred liability.[153]

In contrast to the first alternative proposal, which would remain in place through the end of 2018 regardless of intervening rate cases, the second proposal would be revisited in the Company's next base rate case. Revisiting the issue in the next case is necessary to guard against uncontrollable variability resulting from factors beyond the Company's control, such as financial market performance, mortality rates, or retirement rates.[154] The Company also proposes that it be allowed to request changes to this second mitigation mechanism between now and a post-2016 rate case if significant, material changes to actual qualified pension expense cause wide variances between the normalized pension expense and either the actual or forecasted amount.

The Company believes that both of these proposals are fair representations of the actual pension expense between now and 2018, and they provide customers with a mitigation mechanism that defers part of the current pension expense. The proposals also provide rate stability insofar as qualified pension expense is concerned over a multi-year period. Thus, if the Commission is inclined to adopt a mechanism to moderate qualified pension expense, the Company requests that the Commission adopt one of these two mechanisms.

6. Modifications to the moderation mechanism are not warranted

The Department opposes both of the Company's proposed mechanisms to moderate pension expense, but it considers the second one to be "least objectionable."[155] If the Commission decides to adopt that mechanism, the Department asks that it be modified in four respects. The Commission should deny

[153] Ex. 83, Schrubbe Rebuttal at 36.
[154] Ex. 83, Schrubbe Rebuttal at 37.
[155] Department Initial Brief at 115.

the first, third and fourth requested modifications; the second proposed modification is not really a modification at all because the Company's original proposal includes the feature that the Department advocates.

a. The Commission should reject the Department's recommendation that the Company be denied a return on any deferred amount

The Department first requests that the Company not be allowed to earn a return on any deferred amounts. Its reasons are that the Company "already receives a return on the prepaid pension asset" and that allowing the Company to earn a return would provide "an inappropriate incentive to make poor investment choices for pension assets."[156] Neither reason has any merit.

As noted in the Company's testimony, the prepaid pension asset consists of amounts in the pension trust fund that have not yet been recognized as expense.[157] The Company properly receives a return on those amounts because shareholders have essentially paid the pension expense before it is due, either through contributions or asset returns that cannot be removed from the trust. In contrast, the deferred amount that would accrue under the Company's second mitigation mechanism consists of pension expense that *has* come due, but has not been paid by customers. Thus, it too is being funded by shareholders, and those shareholders should earn a return on that amount in addition to the return on the prepaid pension asset. The Department is essentially making the argument that because the Company is earning a return on one prepayment, it should not earn a return on a different prepayment. That cannot be reconciled with fundamental principles of ratemaking.

The argument that allowing a return would motivate the Company to make poor investment choices is also flawed. The argument is not well developed, but the

[156] Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).
[157] Ex. 82, Moeller Direct at 122.

Department is presumably contending that the Company will deliberately seek out low returns on the pension trust assets so that it can drive up pension expense and earn a return on the difference between the higher pension expense and the amounts paid by customers. But the Company's proposal allows recovery of the *lesser of* actual pension expense or currently forecasted amounts.[158] If the Company changed its allocation to drive up actual expense, it would still be capped at the forecasted amount. Thus, the Company has no incentive to make poor investment decisions; especially when considering the Company's fiduciary duties in managing the pension trust.

b. The Company agrees to continue the current deferral for the XES Plan

The Department's second proposed modification is that the "overall normalization proposal from the last rate case should impact the new alternative normalization proposals," such that "the $1,054,357 deferral for 2013 XES cap that the Commission decided in Xcel's 2012 rate case should be allowed continued deferral."[159] The Company proposed that feature as part of its rebuttal testimony.[160]

c. The Commission should reject the argument that the Company be required to justify recovering the deferred amount in future cases

The Commission should reject the Department's recommendation that the Company "be required to make a case for why the Company should be allowed to amortize any unfunded balances in the future."[161] The deferred amounts will consist of the Company's actual pension expense, which the Department admits is a legitimate cost of service. Given that the deferral is for the benefit of customers, not

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[158] Ex. 83, Schrubbe Rebuttal at 35.

[159] Department Initial Brief at 116.

[160] Ex. 83, Schrubbe Rebuttal at 37 ("[A]kin to our first proposal, we believe it would be reasonable to continue deferring the XES Plan cap amounts until the normalization period ends.").

[161] Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).

the Company, there is no reason to require the Company to bear the burden of proving its right to recover the deferred amounts in future cases.

d. The Commission should reject the Department's recommendation that the discount rate be set equal to the EROA

The Department's fourth proposed modification is that the Company be required to calculate the allowed pension expense in each year using a discount rate equal to the EROA.[162] The Commission should reject that proposed modification for the reasons set forth in the next section of this reply brief.

7. FAS 106 Expense

The Department's argument for excluding the 2008 Market Loss from the calculation of FAS 106 retiree medical expense is identical to the argument for excluding the 2008 Market Loss from the calculation of qualified pension expense. Because the proposed disallowance of the 2008 Market Loss from the calculation of qualified pension expense is improper for the reasons set forth in the Company's initial brief and this reply brief, the proposed exclusion of the 2008 Market Loss from the calculation of FAS 106 expense should be rejected as well.

8. Conclusion

The prior-period loss from 2008 should be included in the calculation of current pension expense and FAS 106 expense, just as prior-period gains have been included for many years in the calculations of current pension and retiree medical expense. The Department has provided no valid reason to exclude any part of the 2008 Market Loss. In fact, even though their reasons for making a downward adjustment have changed throughout this proceeding, the amount of the adjustment has not. Customers have reaped enormous benefits from the inclusion of prior-period gains, and it would be inequitable to single out one loss event to exclude. If

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[162] Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).

the Commission concludes that pension expense should be moderated, one of the Company's two alternative proposals should be used, without the modifications proposed by the Department.

E. Pension and FAS 106 Expense – Discount Rate

In its initial brief, the Company explained that it establishes the rate used to discount the XES Plan pension liability to present value by performing a bond-matching study.[163] For 2013, the bond-matching study conducted by the Company yielded a discount rate of 4.74%, which is the rate used by the Company to calculate its FAS 87 qualified pension expense.[164] That rate is reasonable because it is consistent with the discount rate used by utilities and other large companies, and because customers have benefited from the lower interest rates reflected in that discount rate.[165]

The Department urges the Commission to reject the Company's proposed discount rate and to require that FAS 87 pension expense be calculated instead using a discount rate that matches the EROA.[166] The Department's argument lacks merit for numerous reasons.

1. It is not required to use the EROA the discount rate

Throughout its argument that the EROA should be used as the discount rate for purposes of calculating FAS 87 pension expense, the Department repeatedly asserts that the Employee Retirement Income Security Act (ERISA) requires the EROA to be used as the discount rate for purposes of calculating pension funding.[167]

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[163] Company Initial Brief at 64.

[164] Ex. 83, Schrubbe Rebuttal at 39-40.

[165] *See* Company Initial Brief at 65-66.

[166] Department Initial Brief at 97-107.

[167] Department Initial Brief at 99 ("Pension Fundamentals also points out that, *for funding purposes* under [ERISA], the interest rate used to discount future benefits to today's dollars is based on the 'expected future return on pension assets'; that is, the EROA." (emphasis in original); *id.* at 101 (stating that the "Department's showing is significant that other accounting methods, like the ACM, as well as pension *funding*

According to the Department, the "fact" that the EROA must be used for pension funding confirms that the EROA is also appropriate for calculating qualified pension expense for ratemaking purposes.[168] In support of that argument, the Department cites to statements in a 2004 document attached to Ms. Campbell's testimony entitled "Fundamentals of Current Pension Funding and Accounting for Private Sector Pension Plans" (Pension Fundamentals).[169]

The flaw in the Department's argument is that the law has changed since the American Academy of Actuaries published the Pension Fundamentals document in 2004. In 2006, Congress enacted the Pension Protection Act, which amended ERISA to require that the discount rate used for purposes of pension funding be established using a corporate bond yield curve, not the EROA.[170] As noted earlier, the Company uses corporate bond yields to set the discount rate for the XES Plan. Thus, under the Department's own reasoning that the discount rate prescribed by ERISA for pension funding should also be used for ratemaking, the Company's 4.74% discount rate is appropriate and should be approved by the Commission for calculating the FAS 87 pension expense.

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requirements under ERISA better meet the ratemaking goals of being reasonable and in the public interest while supporting a financially viable utility 'in the long run'").

[168] Department Initial Brief at 99-100 (stating that the "fact that pension funding requirements use the same longer timeframe to determine both the . . . discount rate and EROA assumptions . . . confirms as reasonable the Department's recommendation for the XES Plan discount rate analysis for ratemaking"); *id.* at 98 (stating that "the Department's recommended level of pension costs is consistent with the funding requirements whereas Xcel's proposal is higher than its funding requirements").

[169] Department Initial Brief at 99.

[170] *See* 29 U.S.C. § 1083(h)(2)(C) (requiring that interest rates used to determine funding targets be based on a "corporate bond yield curve"). ERISA defines "corporate bond yield curve" to mean, "with respect to any month, a yield curve which is prescribed by the Secretary of the Treasury for such month, and which reflects the average, for the 24-month period ending with the month preceding such month, of monthly yields on investment grade corporate bonds with varying maturities and that are in the top 3 quality levels available." *Id.* § 1083(h)(2)(D). The Company's bond-yield study also requires the use of bond yields from investment grade corporate bonds. Ex. 82, Moeller Dir. at 82.

2. The discount rate should be evaluated on a case by case basis

The Department also relies on the fact that the Commission approved the use of the EROA as the discount rate for the XES Plan calculation in the Company's last rate case, Docket No. 12-961.[171] But as Mr. Schrubbe noted in rebuttal testimony, the Commission expressly stated in its Docket No. 12-961 Order that it was concurring with the ALJ's discount rate recommendation "on the record in this case."[172] Moreover, in the recent CenterPoint case, the Commission declined to follow the result reached in Docket No. 12-961, but instead concluded that the "calculation of pension expenses requires actuarial assumptions appropriate to the factual circumstances in each case."[173] Thus, the issue of what discount rate to use must be evaluated anew in each case based on the facts of that case.

3. Selection of Actuarial Assumptions

The Department casts doubt about the actuarial assumptions used to calculate the Company's qualified pension expense by arguing that "the Company, not the actuary (Towers Watson) selected the pension assumptions."[174] While the implication, without any substantiated proof in support, is that the Company is selecting improper actuarial assumptions, the evidence on the record establishes that the actuarial assumptions are set in accordance with objective, verifiable benchmarks and are evaluated by the Company's actuary, Towers Watson, in accordance with standards imposed by the American Academy of Actuaries' Actuarial Standards of Practice (ASOP).

The FAS 87 discount rate, for example, is based on objective bond-yield studies and is validated by reference to third-party benchmarks, such as the Citigroup

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[171] Department Initial Brief at 104-105; Ex. 429, Campbell Direct at 117-118.

[172] Ex. 83, Schrubbe Rebuttal at 42.

[173] Ex. 83, Schrubbe Rebuttal at 42-43 (quoting the CenterPoint order).

[174] Department Initial Brief at 97.

Benchmark and the Citigroup Above Median Benchmark.[175] The Company also reviews general survey data provided by Towers Watson and the Edison Electric Institute to assess the reasonableness of the discount rate.[176] Moreover, to avoid reservations expressed by Towers Watson, the Company is required to follow the standards set forth in FAS 87 for calculating the discount rate, as well as the standards set forth in ASOP 4, ASOP 27, and ASOP 35.[177]

Outside actuaries and auditors also play an important role in assessing the reasonableness of the assumptions. For example, Towers Watson participates in the selection of assumptions by providing benchmarking information and reviewing the assumptions relative to historical plan experience.[178] In addition, actuaries are generally asked to prepare a detailed analysis that supports the discount rate selection.[179] The actuaries themselves are subject to professional standards with respect to the work they perform for the plan sponsor, and failure to abide by those standards could result in professional discipline for the individual actuary and significant liability risk for the actuary's employer.[180]

Moreover, the plan sponsor must have an independent auditor, which reviews and evaluates the reasonableness of the assumptions.[181] Those assumptions must

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[175] Ex. 83, Schrubbe Rebuttal at 8; Ex. 82, Moeller Direct at 82.

[176] Ex. 83, Schrubbe Rebuttal at 7.

[177] ASOP 4 is entitled "Measuring Pension Obligations and Determining Pension Plan Costs or Contributions"; ASOP 27 is entitled, "Selection of Economic Assumptions for Measuring Pension Obligations"; and ASOP 35 is entitled, "Selection of Demographic and Other Noneconomic Assumptions for Measuring Pension Obligations." Ex. 85, Wickes Rebuttal at 4.

[178] Ex. 85, Wickes Rebuttal at 5.

[179] Ex. 85, Wickes Rebuttal at 5.

[180] Ex. 85, Wickes Rebuttal at 6. If a plan sponsor were to select assumptions or use methods to develop assumptions that were unreasonable, the actuary would have a responsibility to disclose his or her concerns. *Id.* Failure to do so exposes the actuary to professional discipline. *Id.*

[181] Ex. 85, Wickes Rebuttal at 5.

have sufficient documentation to satisfy the auditor, including documentation of the bond portfolio analysis that forms the basis of the bond-yield study.[182]

Similar to the discount rate, the EROA is developed jointly with a third-party consultant and validated against other advisor benchmarks and expected returns by asset class provided by Towers Watson.[183] The Company also compares the EROA to the expected returns used by other utilities.[184] Likewise, the wage increase assumptions are based on part on a long-term inflation rate taken from a Philadelphia Federal Reserve 10-year inflation forecast.[185] Finally, the Company's independent auditor reviews the reasonableness of the EROA and wage increase assumptions each year.[186]

As this evidence shows, the Company's actuarial assumptions are based on – and tested against – third party benchmarks and objective, verifiable information. Thus, the Department's insinuation that the Company can choose whatever actuarial assumptions it wants is simply wrong.

4. Responding to the Department's remaining arguments

The Department alleges that the Commission should set the EROA and the discount rate at the same level because they measure asset returns and liabilities for similar forward-looking time periods.[187] The Company disagrees, but if the Commission accepts the rationale that the two percentages should match because they measure returns for similar time periods, it makes as much sense to reduce the EROA to the current discount rate level as it does to increase the discount rate to the EROA level. Both modifications will result in an artificial number, with the reduction to the

[182] Ex. 85, Wickes Rebuttal at 5.
[183] Ex. 83, Schrubbe Rebuttal at 7; Ex. 82, Moeller Direct at 98.
[184] Ex. 83, Schrubbe Rebuttal at 7.
[185] Ex. 83, Schrubbe Rebuttal at 8
[186] Ex. 83, Schrubbe Rebuttal at 8.
[187] Aug. 15 Tr. at 42.

EROA making pension expense appear larger than it is, and the increase to the discount rate making the pension expense appear smaller than it actually is. Nowhere does the Department explain why matching the two numbers necessitates an increase to the discount rate, instead of a reduction to the EROA.[188]

The Department also advances several arguments to the effect that rates need not be set according to accounting standards.[189] The Company does not disagree with that assertion, but there should be a good reason to force the Company's ratemaking books to diverge from its accounting books. The Department has provided no such reason, other than a desire to drive pension expense lower.[190] In contrast, the Company has explained that requiring the use of the EROA as the discount rate would give customers credit for more pension expense than they have actually paid, and it would deprive the Company of an opportunity to recover the true present value of actual pension expense that will have to be paid to retirees at some point in the future.

Moreover, the Company's customers already benefit from a higher discount rate relative to other utilities' discount rates. Approximately 73% of the Company's pension cost is attributable to the NSPM Plan, and the Company uses the EROA as the discount rate for the calculation of pension expense for that plan.[191] In contrast, other Minnesota utilities frequently use a discount rate that is considerably lower than the EROA to calculate their entire pension expense. For example, in the recent CenterPoint case, the Commission approved the use of a five-year average of discount

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[188] Indeed, using the discount rate for both purposes makes more sense, because it is a more stable number from year to year than the EROA is. *See, e.g.*, Ex. 83, Schrubbe Reb. at 44 (showing that the discount rate varied by less than 130 basis points over a five-year period).

[189] Department Initial Brief at 97-98; *id.* at 102-104.

[190] Department Initial Brief at 97 (stating that "it is important to keep in mind that a lower assumed discount rate assumption for one of the two Xcel pension plans results in higher calculated pension expense for rates").

[191] Ex. 83, Schrubbe Rebuttal at 45.

rates to calculate CenterPoint's qualified pension expense, instead of using the EROA. That five-year average was 5.35%, although CenterPoint's EROA was 7.25%.[192] Thus, the Commission-approved discount rate was 190 basis points lower than the EROA for CenterPoint's entire qualified pension expense balance, whereas the difference between the Company's FAS 87 discount rate and the EROA affects only 27% of the Company's qualified pension balance. Accordingly, the weighted average of the Company's discount rates is 6.57% (.73 x 7.25 + .27 x 4.74), which is 122 basis points higher than the 5.35% discount rate approved in the CenterPoint case.[193]

5. In the alternative, a five-year average discount rate should be used

In the most recent CenterPoint case, the Department also argued that the discount rate for qualified pension expense should equal the EROA.[194] The Commission rejected that argument and concluded instead that the discount rate should be set using a five-year average.[195]

The Company believes that the discount rate it has proposed for FAS 87 qualified pension expense is appropriate for the reasons outlined in the evidence and briefing. However, if the Commission decides in this case not to use the discount rates proposed by the Company, it should instead use a five-year average of discount rates to calculate qualified pension expense. As shown in the rebuttal testimony of Mr. Schrubbe, a five-year average of the Company's discount rates is 5.05%.[196]

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192 Ex. 83, Schrubbe Rebuttal at 46.

193 Ex. 83, Schrubbe Rebuttal at 46.

194 Ex. 83, Schrubbe Rebuttal at 42.

195 The Company also notes that the Commission adopted a five-year historical average for setting the discount rate during its deliberations of the recent MERC natural gas rate case. At the time of this Reply Brief, the Commission had not yet issued its order.

196 Ex. 83, Schrubbe Rebuttal at 47. This assumes the Commission accepts the December 31, 2013 measurement date for calculating pension expense. The deferral amount using a December 31, 2012 measurement date would lead to a deferral of $1.69 million. *Id.*

6. Deferral Offset

As noted earlier, in Docket No. 12-961, the Commission agreed with the Company's proposal to cap its FAS 87 pension expense at the 2011 level, which was approximately $5.4 million.[197] The effect of that cap in this case is to reduce the Company's FAS 87 pension expense by approximately $1.5 million.[198]

If the Commission were to accept the Department's recommendation to use the EROA as the discount rate for purposes of calculating FAS 87 qualified pension expense, it would reduce the FAS 87 expense by approximately $1.7 million, which is roughly $216,000 higher than the deferred amount. Thus, acceptance of the Department's recommendation would result in a disallowance of $216,000, not the $1.7 million that Ms. Campbell identified.

In surrebuttal Ms. Campbell argues that the Commission's order in Docket No. 12-961 does not allow "the 2008 Market Loss to be carried into the present case," and therefore she contends the deferred amount should not offset any reduction attributable to a reduced discount rate.[199] But the deferral approved in Docket No. 12-961 was not specific to the 2008 Market Loss. It was instead a more general mitigation mechanism approved by the Commission to moderate pension expense. Therefore, whether the 2008 Market Loss can be included in pension expense in this case has no bearing on the continued viability of the FAS 87 cap.

To be clear, the Company does not believe that the Commission should accept the Department's recommendation on the discount rate. The arguments advocating the disallowance are wrong for the reasons set forth in this Reply Brief, and even if the disallowance is relatively small in 2014, it would be considerably larger in subsequent years. Therefore, this continues to be an important issue to the Company.

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[197] Ex. 83, Schrubbe Rebuttal at 46.
[198] Ex. 82, Moeller Direct at 51.
[199] Ex. 435, Campbell Surrebuttal at 86.

7. Conclusion

For the reasons outlined in the Company's initial brief and this reply brief, the Commission should approve the use of the 4.74% discount rate proposed by the Company for calculating qualified pension expense. And because the Department has identified no separate reason to use the EROA to set FAS 106 retiree medical expense, the Commission should approve the 4.82% discount rate proposed by the Company for that calculation.

F. Total Labor Adjustment

The Company fully justified its 2014 cost of service, including its total labor costs, in this proceeding. In its Initial Brief, the Company demonstrated that virtually all of the Department's proposed total labor adjustment was due to increased labor costs for our Nuclear Business Area and our Business Systems Business Area and that the record provided a full, complete and unrebutted justification of the reasonableness and necessity of these increased costs.[200]

In its Initial Brief, the Department continues to advance an approximately $5.6 million downward adjustment to the Company's test year labor costs. The reasons for the adjustment remain unchanged and so should the outcome[201] – rejection of the Department's adjustment as being incorrect, arbitrary, non-substantive, and unreasonable. As the Company explained in its initial brief, the Company did "detail the basis for its 3.9 percent annualized increase amount for the 2014 test year"[202] through the direct testimony of several business unit witnesses. No party refuted the testimony of these witnesses.

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[200] Company Initial Brief at pp. 70-71.

[201] The Company notes that similar total labor cost information was provided in the Company's direct case for analysis. Ex. 86, Stitt Direct at Schedule 3(a).

[202] Department Initial Brief at p. 158.

The Department insinuates that the Company failed to meet its burden because Company witness Ms. Stitt did not respond to the Department's total labor cost adjustment in her rebuttal testimony.[203] At the outset, the Company notes the Department raised the total labor adjustment anew in surrebuttal. As a result, the Company did not have an opportunity to provide written testimony to rebut the Department's adjustment.

Irrespective of this fact, the Department is simply wrong: the Company has met its burden of proof. As previously mentioned, the record is replete with information from Company business unit witnesses, including Ms. Stitt, justifying the Company's labor costs during the test year.[204] Additionally, in her opening statement at the evidentiary hearing, Ms. Stitt utilized the Department's proposal to identify the drivers of the Company's total labor cost increases that exceed the Department's three percent labor cost cap for the test year.[205] Specifically, the Company provided ample evidence that structural changes within the Nuclear Business Area and Business Systems Business Area are accounting for the growth above the Department's arbitrary cost cap in light of the additional employees these business areas are hiring due to demonstrated need.[206]

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[203] The Company notes Ms. Stitt's rebuttal testimony was submitted to rebut the Department's now abandoned paid leave adjustment. Ex. 87, Stitt Rebuttal at p. 1 ("I respond to the Direct Testimonies of Department of Commerce Witnesses Ms. Nancy C. Campbell regarding Paid Leave costs…).

[204] *See generally*, Ex. 86, Stitt Direct at pp. 26-38, Schedule 3(a) (showing that the Company's budget total labor cost is generally representative of its actual incurred costs). *See also,* Ex. 51, O'Conner Direct at pp. 81-118 (detailing the Nuclear Business Area's O&M costs and trends); Ex. 62, Harkness Direct at pp. 56-83 (detailing the Business System's Business Area's O&M costs and trends); Ex. 58, Mills Direct at pp. 7-40 (detailing the Energy Supply Business Area's O&M costs and trends); Ex. 65, Kline Direct at pp. 9-27 (detailing the Transmission Business Area's O&M costs and trends); Ex. 69, Foss Direct at pp. 6-27 (Detailing the Distribution Business Area's O&M costs and trends).

[205] Ex. 129, Stitt Opening Statement at p. 2; Tr. Vol. 2 at pp. 38-39 (Stitt).

[206] Ex. 51, O'Conner Direct at pp. 83-90; Ex. 62, Harkness Direct at pp. 76-80.

The Department has not rebutted the Company's *prima facie* case with respect to the representativeness and reasonableness of its total labor costs and the proposed total labor adjustment should be rejected.

IV. OTHER DISPUTED REVENUE REQUIREMENT ISSUES

A. Prairie Island EPU

The Company and the Department have reached a reasonable resolution with respect to recovery of the costs of the Company's cancelled extended power uprate (EPU) project at its Prairie Island nuclear generating facility (Prairie Island).[207] This resolution applies the proper standard to the review of the Company's costs of the Prairie Island EPU[208] and provides a just and reasonable outcome. Consequently, the ALJ and the Commission should accept this resolution as part of this proceeding.

Notwithstanding the just and reasonable outcome agreed to by the Company and the Department, the ICI Group and the OAG both proposed adjustments to the Company's revenue requirement with respect to the recovery of the costs of the Prairie Island EPU. These adjustments should be rejected. The ICI Group applies the wrong standard to the Prairie Island EPU costs to arrive at its proposed adjustment. While the OAG attempts to cast doubts based on hindsight review of the Prairie Island project, it has not shown that the Company did not incur costs or accrue AFUDC for the Prairie Island EPU costs in good faith.

1. The ICI Group Imposes the Wrong Standard

Commission precedent is clear that the prudence standard and not the used and useful standard is applicable to review for recovery of costs for abandoned projects.

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[207] *See* Department Initial Brief at pp. 46-53.

[208] Department Initial Brief at 45-48 (discussing Commission precedent and applicable standard with respect to rate recovery of cancelled projects).

> The appropriate standard of review to apply to the Prairie Island cancelled Project is the prudence Standard… [T]he prudence standard does not rely on hindsight evaluation.
>
> ***
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> In recent years, several cancelled projects have been brought to the Commission for review and examination of requests for cost recovery. In these cases, the Commission has focused on the reasonableness of the utility's decisions and of the costs incurred during the project's active and wind-down phases.[209]

The ICI Group disregards this history of evaluation of cancelled project costs under the prudence standard and instead seeks to apply the used and useful standard to the costs of the Prairie Island EPU Project.[210] The ICI Group's proposal is not persuasive. First, the weight of Commission precedent has set forth the appropriate standard for recovery of cancelled project costs.[211] Second, it is settled law that recovery of the costs of cancelled projects and the used and useful standard can and do coexist, and that a statutory used and useful standard does not bar the recovery of cancelled project costs.[212] Third, it cannot be the case that cancelled projects must be "used and useful" to be eligible for rate recovery; if that was the policy, no utility could ever recover the costs of a project undertaken for customers' benefit and then

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209 Ex. 99, Clark Direct at p. 32.

210 ICI Group Initial Brief at p. 7-12.

211 *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service In Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER, Docket No. E-001/GR-10-276 (August 12, 2011) (allowing recovery of the costs of the cancelled Sutherland Generation Station Unit 4 Project under the prudence standard); *In the Matter of the application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER, Docket No. E-017/GR-10-239 (April 25, 2011) (allowing recovery of the costs of the cancelled Big Stone II generating facility under the prudence standard).

212 *See, e.g.*, James J. Hoecker, "USED AND USEFUL": AUTOPSY OF RATEMAKING POLICY, 8 Energy Law Journal 303 (1987) (discussing at length the used and useful concept and how case law has evolved to allow for the recovery of cancelled projects within these concepts).

cancelled due to changes in circumstances. Therefore, the ICI Group proposed adjustment is unjustifiable and should be rejected.

2. Costs Incurred and AFUDC Accrued in Good Faith

The record reflects that the Company accounted for the costs of the Prairie Island EPU Project and accrued AFUDC for the project appropriately:

> Our independent external auditors did not take exception to our accounting for the Prairie Island EPU costs in either their audits of the Company's 2012 and 2013 GAAP basis financial statements of their audits of the Company' 2012 and 2013 FERC basis financial statements.[213]

As discussed in detail in the Company's Initial Brief, the record further establishes that the Company reasonably incurred the costs of the Prairie Island EPU Project and accrued AFUDC appropriately. The OAG, however, continues to insist that there was some point in August 2011 when it became clear the Company should have cancelled the Project altogether, and therefore should not have incurred costs or accrued AFUDC after that time.

The OAG argues that "[n]ationwide precedent supports the OAG's recommendation to disallow AFUDC accumulated after August 2011,"[214] but in fact cites only a single case for the proposition that both a portion of Project costs and AFUDC should be disallowed. In fact, both the Company and the OAG rely on this same Massachusetts and FERC[215] precedent regarding Boston Edison Company's (BEC's) planned Pilgrim II nuclear plant, which was subsequently abandoned, to argue the appropriateness of the costs and accrual of AFUDC for the Prairie Island EPU project.

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213 Ex. 47, Weatherby Rebuttal; *see also* Ex. 94, Perkett Rebuttal at pp. 31-37 (discussing the appropriate FERC AFUDC requirements applicable to the Prairie Island EPU project and the Company's compliance therewith).

214 OAG Brief at 14.

215 *Boston Edison Company*, 34 FERC ¶ 63,023 (1986); *Boston Edison Company,* 46 P.U.R. 4th 431, 471–74 (Mass. D.P.U. Apr. 30, 1982); *Attorney General v. Department of Public Utilities*, 455 N.E.2d 414, 421 (Mass. 1983).

Consistent with Minnesota law, the FERC determined the issue with respect to the Pilgrim II case was whether Boston Edison "acted in good faith and in the interests of both its ratepayers and stockholders in keeping open the nuclear option until September 1981."[216] In other words, FERC applied the prudence standard to the cancellation date of the project at issue in *Boston Edison Company*:

> A review of the evidence in this proceeding shows that only in hindsight can one say with any degree of certainty that Pilgrim II should have been cancelled at an earlier date. Viewed from a 1978, 1979 or 1980 perspective it was not unreasonable or imprudent for BEC's management and Board of Directors to conclude that the cost advantages of Pilgrim II power made the risks or uncertainties associated with the project worth taking. Similarly, in September 1981, it was reasonable and prudent for BEC to cancel Pilgrim II when it concluded that the risks and uncertainties showed no signs of abatement.[217]

Under this standard, the Company must prevail.

The OAG is applying the hindsight analysis rejected by FERC in *Boston Edison Company* by arguing, that "Xcel continued to incur costs for the Prairie Island EPU and accrue AFUDC <u>after it should have known that the project was no longer viable</u>."[218] The OAG's logic is essentially that because the Prairie Island EPU project was ultimately cancelled, the Company should have known it was going to be cancelled while the issues that ultimately led to its cancellation were still unfolding. This logic requires perfect knowledge on the part of the Company and ignores key facts in evidence on the record. The Company's careful management and continuing assessment of the project during 2011 and 2012 demonstrate that the Company was

[216] *Boston Edison Company*, 34 FERC ¶ 63,021 at 65,069 (1986).
[217] *Boston Edison Company,* 34 FERC ¶ 63,023 at 65,071 (1986).
[218] OAG Initial Brief at p. 7.

appropriately managing the Prairie Island EPU project consistent with the uncertainty surrounding the project.

The evolving circumstances the Company faced in 2011 and 2012 are part of robust discussion in the Company testimony of Mr. McCall and Mr. Alders. Among other things, Mr. McCall explains in detail how the NRC provided information that the licensing process would be longer and more complex than the Company could have known, but also details the Company's thorough analysis of these changes as information evolved.[219] Thus it is not correct, as the OAG asserts without support, that "Xcel decided to begin a ramp down process following its meeting with the NRC on August 18, 2011" or that the Company "acknowledged [at that time] that the project was no longer viable."[220] Rather, the Company took the additional information from the NRC, "assessed the likely cost of the required additional design efforts," and reasonably estimated the additional cost requirements.[221] Such estimates reasonably take time to develop internally and with vendors, and in any event were only one part of the Company's overall assessment. It is critical to note that this information did not lead to a conclusion that the Project was no longer viable. Rather, throughout 2011 and the first three quarters of 2012 the Company's and Department's models continued to illustrate net benefits for the Project.[222]

Nor does OAG offer a valid comparison of the circumstances surrounding the Prairie Island EPU and the known facts regarding BEC's Pilgrim II plant. OAG is

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[219] Ex. 49, McCall Direct at 28-31.

[220] OAG Initial Brief at 15.

[221] Ex. 49, McCall Direct at p. 30-31.

[222] Ex. 48, Alders Direct at 13-18. It is also inappropriate to suggest that the Company did not properly keep the Commission informed. The Notice of Changed Circumstances rule requires a filing only when certain specific circumstances regarding size, type, and timing of the project are met. Minn. R. 7849.0400. Here, the Company provided information about timing delays in the Certificate of Need application process and came back to the Commission when it appeared a further delay was likely following the end of 2011. Ex. 49, McCall Direct at 14. And although the project output changed somewhat in 2011, this change did not arise to the 20 percent or 80 MWs that would require recertification under Minn. R. 7849.0400, subp. 2(B). Ex. 49, McCall Direct at 26.

correct that the Massachusetts Commission concluded that BEC should have cancelled the Pilgrim II project earlier than it did, and attempts to distinguish FERC's contrary conclusion that the project costs were fully recoverable. In doing so, however, OAG understates the clarity of circumstances in the Pilgrim II case. OAG contends, for example, that "just as in this case, after Three Mile Island, BEC learned that there would be a significant delay and increase in cost in gaining permits and licensing from the NRC."[223] This is not a simple comparison between licensing delay circumstances; rather, nine months before the date on which the Massachusetts Commission concluded BEC should have cancelled the Pilgrim II project, "the NRC [had] announced a halt in licensing pending the results of the presidentially commissioned Kemeny' review."[224] The Company never encountered a moratorium that called the overall viability of the Project into question, but rather had to calculate the potential risks and benefits of a far more unclear NRC process. In addition, BEC's inability to finance the Pilgrim II project – a situation Prairie Island never faced – further contributed to the state commission's finding that the project should have been cancelled earlier.[225]

OAG also attempts to distinguish the FERC's full-cost-recovery decision with respect to Pilgrim II by suggesting that "FERC found arguments about uncertainty in demand growth to be unpersuasive, but in this case Xcel has affirmatively acknowledged that its updated estimates showed reduced demand growth."[226] The record in this proceeding reflects, however, that while a reduced growth in demand would have reduced project benefits, overall, "the Project still continued to be cost-

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[223] OAG Initial Brief at 14-15.

[224] *Boston Edison Company,* 46 P.U.R. 4th 431 (Mass. D.P.U. Apr. 30, 1982).

[225] *Boston Edison Company,* 46 P.U.R. 4th 431 (Mass. D.P.U. Apr. 30, 1982).

[226] OAG Initial Brief at 16 (citing Ex. 48, Alders Direct at 15).

effective."[227] There can be no reasonable claim that the Company should have cancelled a project in August of 2011 when that project was viable and remained viable until the Commission issued an order withdrawing the Certificate of Need.

Overall, the OAG ignores that at every stage of the Company's review of the prudence of continuing the PI EPU project, the overall cost/benefit analysis showed a positive present value of revenue requirement (PVRR) for the project.[228] In fact, based on the facts available as late as May of 2012, the Department still recommended moving forward with the project:

> In response to the Notice of Changed Circumstances, the Department of Commerce Division of Energy Resources (Department) provided comments on the Company's analysis. Upon initial review, the Department stated that preliminary results showed the EPU Project was cost effective despite delays in timing and updated assumptions.[229]

This is at least 16 months after the OAG believes the Company should have affirmatively cancelled the project.[230] Thus at no point had "'uncertainty become intolerably high' and cancellation was the only prudent course of action."[231]

The Company's management of the Westinghouse contract provides a further example of how the Company managed the project through uncertainty, based on the information available at the time. Westinghouse was the Company's key contractor for the work necessary to obtain the NRC license amendments for the Prairie Island

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227 Ex. 48, Alders Direct at 15-16.

228 Ex. 48, Alders Direct at 13-18 (discussing the resource planning implications of potential delays in receiving the EPU license amendments from the NRC and how, at worst, it resulted in a break even cost/benefit analysis).

229 Ex. 48, Alders Direct at 19 (citations omitted). Mr. Alders goes on to note that two months later, the Department ultimately determined it was appropriate to cancel the project. *Id.*

230 OAG Initial Brief at p. 9 (determining that the Company should have cancelled project in October, 2010).

231 OAG Initial Brief at p. 15 (citing to *Boston Edison Company*, 46 P.U.R. 4th 431, 471-474 (Mass. D.P.U. April 30, 29182)).

EPU project.[232] We worked closely with Westinghouse and developed a milestone based contract pursuant to which Westinghouse would receive guaranteed lump sum payments upon achieving certain project milestones.[233] If the Company terminated the contract without any fault to Westinghouse before a specific milestone was reached, then the Company would have to pay termination charges to Westinghouse.[234] This does not reflect imprudence on the part of the Company, as the OAG suggests for the first time in briefing. Rather, this contract structure reflects industry standards and "protects the Company and our customers in most instances, as it allows us to reserve material cash outlays to a vendor until we are assured the work is substantially complete."[235]

When it became apparent near the end of 2011 that there was a potential to cancel the project, the Company was faced with a decision of whether to terminate the Westinghouse contract and pay the termination penalties or allow Westinghouse to complete its work. "[B]ecause our cost-benefit analysis of the overall Project did not clearly point to cancellation, we determined that it was better to receive the deliverables while our Change in Circumstances filing was considered, rather than terminate the Westinghouse contract prematurely."[236] This decision weighed the costs of termination penalties against the value of the work we would receive from Westinghouse due to the uncertainty of moving forward with the project. The analysis provided by Westinghouse "would be critical to our LAR application if the Project proceeded."[237]

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[232] Ex. 49, McCall Direct at pp. 12-13.
[233] Ex. 49, McCall Direct at pp. 18-19.
[234] Ex. 49, McCall Direct at p. 19.
[235] Ex. 49, McCall Direct at p. 34-35.
[236] Ex. 49, McCall Direct at p. 35.
[237] Ex. 49, McCall Direct at p. 36.

Although the Company did move forward with the Westinghouse contract, it also suspended some work to mitigate costs while proceeding with the project was being considered. For example, "we ceased final review and approval of Westinghouse reports until we knew whether we would proceed with the LAR submittal" which involved not renewing the contracts for twelve engineers. [238] The Company also suspended vendor selection work for EPU major power train equipment and extended the expiration date of the Westinghouse contract to allow us to pick up the LAR at a future time, if needed.[239] And the Company began identifying the best means of ramping down and ending Westinghouse's work on the LAR pending the outcome of the regulatory process.[240] These efforts show that the Company was prudently managing the project to mitigate costs during a period of uncertainty.

The prudence standard requires an analysis of if the utility's action was reasonable <u>at the time it was taken under all relevant circumstances</u>.[241] Clearly, the OAG's use of hindsight is the driver of its proposed disallowance and AFUDC adjustments. Because the OAG is inappropriately applying the prudence standard, its adjustment should be rejected.

3. Full Recovery is Appropriate

The OAG unreasonably takes issue with the fact that the Company was required for financial accounting purposes to take a pre-tax charge of a portion of the Prairie Island EPU costs to reflect the uncertainty of the earning a return on the regulatory asset. Based on this GAAP requirement, the OAG argues that the Company should be denied rate recovery of $10 million of the Prairie Island EPU

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[238] Ex. 49, McCall Direct at p. 34.

[239] Ex. 49, McCall Direct at p. 34.

[240] Ex. 49, McCall Direct at p. 34.

[241] *See* Charles F. Philips, Jr., THE REGULATION OF PUBLIC UTILITIES – THEORY AND PRACTICE at 292 (Public Utility Reports 1988).

costs.[242] This is an erroneous understanding of the financial accounting issues relevant to this project and has no basis in law or fact.

As Company Witness Mr. Scott Weatherby discusses, consistent with GAAP, the Company took a pretax charge of $10.1 million in order to record the full regulatory asset amount on a discounted basis over the 12-year amortization period requested by the Company. This recording of net present value was and is not reflective of the prudence of incurring Prairie Island EPU costs nor any particular ratemaking outcome; rather, it reflects that in light of past Commission precedent in Minnesota, the recovery of a return on these assets was not certain. In other words, this pretax charge reflects that the Company would lose some of the value of the investment by delaying rate recovery into a future period without earning a carrying charge on the asset.[243]

OAG proposes for the first time in briefing that the Company took this pretax charge because the Company "likely was attempting to comply with FASB 980-360-35-3" which requires recognition of a loss when a portion of the costs is expected to be disallowed.[244] This suggestion is not only inappropriate after the record is closed, but is also incorrect. Company witness Mr. Scott Weatherby explained at some length in Direct Testimony, Rebuttal Testimony, and at the evidentiary hearings that the $10.1 million pretax charge reflects the effects of regulatory lag on project recovery and does not represent any actual costs incurred by the Company for the Prairie Island EPU project. Consequently, the Company's request to recover the actual costs of the project with AFUDC and a limited debt return are reasonable and appropriate.

[242] OAG Initial Brief at pp. 18-19.
[243] Ex. 120, Weatherby Opening Statement.
[244] OAG Initial Brief at 18.

B. CWIP/AFUDC

The OAG and Commercial Group continue to support an AFUDC and CWIP accounting treatment that is inconsistent with practices in effect since 1977, and which would undermine the Company's ability to fully recover financing costs for capital projects. In particular, the OAG argues that (i) the Company should not include CWIP in rate base subject to an AFUDC offset; rather, AFUDC should solely be deferred for recovery once the asset goes in service; and (ii) the AFUDC rate should be set according to an OAG-devised formula that does not represent all types of funds used for construction. If adopted, it is undisputed that these proposals would not only alter decades of established AFUDC and CWIP accounting in Minnesota, but also increase the revenue requirement for 2014 by $8.5 million and for 2015 by $12.4 million.[245]

OAG also argues that AFUDC accrual and capitalization should be limited to capital projects costing more than $25 million. However, this threshold is not supported in the record, and would preclude the Company from recovering its costs of capital for a large majority of the Company's capital investments -- totaling 62 percent in the Test Year. Because the Company's present treatment of AFUDC and CWIP is consistent with FERC requirements and long-standing Commission practice and presents a balanced approach, no change in this mechanism is required.

1. The Company Has Met FERC Requirements

At the outset, it is important to recall the Commission's charge to the Company with respect to AFUDC and CWIP in this proceeding. In the Company's prior rate case, the Commission ordered the Company to "<u>provide evidence of FERC's accounting requirements</u> for CWIP/AFUDC and <u>demonstrate that it has met the</u>

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[245] Ex. 94, Perkett Rebuttal at 25.

FERC requirements" in the Company's initial rate case filing.[246] The Company provided this information, establishing that the system of CWIP and AFUDC accounting it has used since 1977 is consistent with the FERC Uniform System of Accounts,[247] and with Minnesota Statutes.[248] No Party suggests otherwise. Thus the Company has met its burden to demonstrate it has met the FERC requirements.

Despite acknowledging the Company's compliance with FERC accounting rules, the OAG suggests removing CWIP from rate base and the corresponding AFUDC offset from the income statement "so that Xcel does not earn a current return on projects that are not used and useful."[249] According to the OAG, this would "ensure that ratepayers are not paying Xcel a return for projects that are incomplete."[250]

Here, the OAG continues to fundamentally misapprehend both Minnesota statutes and the nature of AFUDC and CWIP accounting.

First, Minnesota law expressly contemplates the inclusion of CWIP in rate base:

> ... In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost …, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to expenses of a capital nature….[251]

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246 ORDER at 10, Docket No. E002/GR-12-961 (emphasis added). The Commission's Order further required consideration of whether a cost threshold should be established for including CWIP in rate base. That subject is discussed in the Company's testimony, Initial Brief, and later in this Reply Brief.

247 FERC Uniform System of Accounts, Plant Instructions Section 3(17); FERC ORDER 561 (establishing the formula for AFUDC in 1977); Ex. 92, Perkett Direct at 54-55.

248 Minn. Stat. § 216B.16, subds. 6 and 6a; Ex. 92, Perkett Direct at 54-56.

249 OAG Initial Brief at 34.

250 OAG Initial Brief at 34.

251 Minn. Stat. § 216B.16, subd. 6 (emphasis added).

Given this statute, it is appropriate to "give due consideration" to the Company's CWIP in order to establish the rate base. The OAG's proposal gives no consideration to including CWIP in rate base, but rather excludes CWIP from rate base in all circumstances. As a result, the OAG recommendation includes only part of the FERC methodology.

The OAG also deviates from FERC methodology by not including corresponding FERC requirement that short-term debt (STD) be excluded from the capital structure used for ratemaking. The OAG claims that: it is not necessary to remove the cost of STD from the capital structure; there is no link between FERC's treatment of CWIP/AFUDC and the removal of STD from the capital structure; and there is no need to remove STD from the capital structure to properly balance the interest of ratepayers and shareholders.[252] To the contrary, Ms. Perkett demonstrated that each of the OAG claims is incorrect. In particular, Ms. Perkett explained that under the OAG proposal to remove CWIP from rate base, it is also necessary to remove STD from the capital structure: (1) to balance the treatment of investments during construction with the treatment of those assets once they go into service.

Second, as noted in testimony, the Company only earns a current return when a project in CWIP is included in rate base <u>without</u> an AFUDC offset on the income statement.[253] Except in limited circumstances for short-term, smaller projects, the Company's CWIP is typically offset by the addition of AFUDC both to rate base and operating income. This combination of CWIP and AFUDC in rate base, along with the AFUDC offset, results in the deferral of construction financing costs until the asset goes into service. Once the asset goes into service, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense. In this way the long-standing Minnesota method of accounting for AFUDC

[252] OAG Initial Brief at 34-35.

[253] Ex. 94, Perkett Rebuttal at 17-18.

and CWIP allows the Company to recover its full financing costs. While the FERC method typically does not include CWIP in rate base, it reaches a similar result by not using an AFUDC offset and otherwise applying a higher rate of return over the life of the asset.[254] Notably, the OAG's proposal says nothing about the rate of return to be applied if CWIP were not included in rate base; as a result, the OAG's proposal would undermine the Company's ability to recover its costs of capital consistent with FERC requirements.

With respect to the calculation of the AFUDC rate, the OAG acknowledges that the FERC Electric Plant Instruction 3(a)(17) "instructs a utility to calculate its AFUDC rate calculating a weighted average of short-term debt followed by a mix of long-term debt and equity."[255] The OAG further does not dispute that this is the Company's method of calculating the AFUDC rate, and that one cannot trace the specific funds used to finance a construction project.[256]

However, in testimony the OAG postulated that equity should not be used in the calculation of the AFUDC rate because cash from operations would fund most if not all Company construction projects.[257] The OAG then argued that the Company should only be able to include equity in its AFUDC rate calculation if the Company could prove it used specific equity funds for a specific capital project.

Although the OAG acknowledged in testimony that funds cannot be traced,[258] in briefing the OAG implies that FERC Electric Plant Instruction 3(17) requires a tracing of equity funds based on the following language:

> (17) *Allowance for funds used during construction* (Major and Nonmajor utilities) includes the net cost for the period of

[254] Ex. 94, Perkett Rebuttal at 17-18, 25.
[255] OAG Initial Brief at 36.
[256] Tr. Vol. 3 at 207, 212, 213 (Lindell); Ex. 320, Lindell Direct at 21.
[257] Ex. 320, Lindell Direct at 28.
[258] [258] Tr. Vol. 3 at 207, 212, 213 (Lindell).

> construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used…[259]

Relying on the "when so used" language, the OAG suggests that "[t]herefore, it is only appropriate to include non-debt sources of funds when a utility can demonstrate that they have actually been used to fund construction projects."[260]

The cited language does not stand for the argument the OAG advances. Rather, this language recognizes that any kind of funds used for construction – whether borrowed funds or any "other funds"– have a cost, such as the cost of debt or the return shareholders expect on their invested equity. Put differently, regardless of whether the funds used for construction are specifically traceable to equity, operations, or debt, the Company has a finite quantity of funding available; if operating debt is used for construction, equity must be used for other purposes and vice versa. Therefore, the costs of all funds taken together are recognized in the FERC AFUDC formula. Based on the recognition in Instruction 3(17) that all funding has a cost, the FERC AFUDC formula uses short-term debt first because it is the least expensive form of funding, and then employs a mix of long-term debt and equity in the AFUDC rate calculation.[261] Because the Company uses the FERC formula that is consistent with the nature of capital investment, the OAG's devised AFUDC formula (consisting solely of the simple average of short- and long-term debt) should be rejected.

The OAG also suggests that the 2.62 percent rate resulting from its AFUDC rate calculation is sufficient, in large part because the Company has access to low-cost cash when it collects excess interim rates. However, this argument ignores that interim rates in excess of final rates are refunded to customers at a cost to the

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259 OAG Initial Brief at 36.

260 OAG Initial Brief at 36.

261 OAG Initial Brief at 36.

Company – which, at Prime Rate, is higher than the cost of comparative short-term debt and higher than the OAG's proposed AFUDC rate. The OAG's argument further assumes the utility will have excess interim rates, which is not always the case during a rate case period let alone during a multi-year rate plan or between rate cases.[262] In addition, the FERC AFUDC formula is intended to reflect long- and short-term debt as well as equity costs, whereas interim rates are most equivalent solely to short-term debt.[263] Consequently, the collection of "excess" interim rates in some cases does not justify the OAG's proposal to set the AFUDC rate even lower than the level of interest on refunded interim rates.

2. A $25 Million Threshold on AFUDC Is Unwarranted

The Commission also ordered the Company to address in its initial filing "whether a minimum dollar level should be set for projects in CWIP."[264] OAG does not suggest that there should be a minimum threshold for including projects in CWIP with or without an AFUDC offset on the income statement; rather, OAG argues that the Company should not be allowed to accumulate AFUDC on projects that cost less than $25 million. This is a fundamentally different proposition, which would deprive the Company of an opportunity to recover the costs of financing smaller projects – which, individually and cumulatively, require the investment of funds just as larger projects require.

In its Initial Brief, OAG first argues that accumulating AFUDC on projects costing less than $25 million is unreasonable because the Company does not need to finance projects that are low in cost.[265] The only cited support for this proposition is Mr. Lindell's opinion, which is contrary to FERC's recognition in Instruction 3(17)

[262] Given the Company's conservative approach to interim rates in this proceeding, it is not yet clear whether any "excess" interim rates have been available.
[263] Ex. 31, Tyson Rebuttal at 23-24.
[264] ORDER at 10, Docket No. E002/GR-12-961.
[265] OAG Initial Brief at 38.

(discussed above) that the various forms of funding used for construction have an associated cost. The OAG goes on to contend that "utilities in other states are fully able to provide reliable electric service to millions of customers while operating under AFUDC caps similar to the one proposed by the OAG."[266] In support, the OAG offers the incomplete and potentially misleading statement that utilities in Florida are only permitted to accrue AFUDC on large projects that are in excess of 0.5 percent of rate base.

As discussed in the Company's Initial Brief, Florida Rule 25-6.0141 (Allowance for Funds Used During Construction) allows utilities to include all projects completed within one year and costing less than 0.5 percent of the balance of Plant in Service in CWIP without an AFUDC offset, thereby earning a current return on CWIP. In short, the Florida rules are consistent with the standard in Minnesota to include less costly, short-duration projects in CWIP without an AFUDC offset or capitalized AFUDC, thereby avoiding accumulating AFUDC for projects considered in service almost immediately.[267] Conversely, projects of longer duration and larger size are subject to AFUDC capitalization in both Florida and Minnesota without a current return on the asset.[268] As a result, there is no support in the record for OAG's claim that utilities in other states operate under an AFUDC threshold like the one proposed here. The Company's present AFUDC and CWIP accounting practice is appropriate, consistent with FERC requirements, and balanced for all stakeholders.

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[266] OAG Initial Brief at 38. The OAG also argues in briefing that the Company's initial filing did not provide substantive discussion of whether it would be appropriate to set a minimum dollar threshold for inclusion of CWIP in rate base. OAG Initial Brief at 38. This is not correct. Ms. Perkett discussed the Company's present treatment of AFUDC and CWIP in detail, explaining why this treatment is appropriate and balanced. Ex. 92, Perkett Direct at 51-63. Based on this discussion, the Company appropriately concluded no threshold is warranted.

[267] Ex. 92, Perkett Direct at 64.

[268] Ex. 324, Lindell Surrebuttal Schedule JJL-1 at 3.

C. Rate Moderation – TDG Theoretical Reserve and DOE Credits

As part of this rate case, we proposed several innovative rate moderation tools in an effort to provide more predictable rate increases as we cross our investment peak. We proposed to accelerate the return of the TDG theoretical reserve funds to our customers with a 50%-30%-20% pattern. We combined this with refunding DOE settlement credits back to our customers in 2015 to absorb the "bounce back" effect of a more aggressive TDG theoretical reserve amortization. Importantly, both concepts were premised off of the assumption that the Company would receive all of the rate relief it requested in this rate case.

Several parties support our proposed accelerated use of the TDG theoretical reserve. The Department generally does as well; however, the Department prefers using a consumption pattern of 50%-40%-10% to further lower the rate increase in 2015. The Company does not support the Department's pattern as the long-term benefits of returning the theoretical reserve to customers more quickly may be outweighed by a greater bounce back effect in 2016.

As it pertains to refunding DOE credits in 2015, the Company believes there is general support for this proposition as explained during the evidentiary hearing. The Company takes no position on CG's proposal to refund the settlement credits in 2014 should the Commission reject the Company's MYRP request.

Much has changed since we filed our case nearly a year ago. Based on the record, as it sits today, the Company believes the heart of the matter is how does the Commission want to use these rate moderation tools for the benefit of our customers. The Company believes there could be value in further modifying the theoretical reserve consumption pattern to 50%-0%-50% depending on the outcome of the key disputed revenue requirement issues discussed above. Such a pattern would preserve a significant amount of the theoretical reserve for future years. The Commission may also conclude there is no need to refund the 2015 DOE settlement credits to customers after resolving the disputed revenue requirement issues. The Commission could also consider other solutions such as moving rate recovery of the Border and Pleasant Valley wind projects from the 2015 Step to the RES rider. All in all, the Commission has the discretion to direct the use of the rate moderation tools in the manner it deems most appropriate, once final rates are otherwise set in this matter.

D. Nuclear Theoretical Depreciation Reserve (2014)

XLI continues to advocate that the Company currently has a surplus nuclear theoretical reserve and that this calculated surplus should be returned to customers over a five-year period, rather than over the life of the Company's nuclear assets, in order to reduce the revenue requirement in this case. As discussed in the Company's initial brief in this matter, the Company disagrees with XLI's assumptions regarding the existence and proper calculation of a surplus, as well as its acceleration proposal. Because the Company's overall position and reasoning is set forth in initial briefing, this Reply Brief responds to only three nuclear theoretical reserve arguments XLI sets forth in its initial brief.

First, XLI argues that its proposal is "supported by the Commission's order in the last rate case."[269] In fact, the Commission concluded in the Company's last rate case that the Company's presently-calculated nuclear theoretical reserve properly accounts for the cost of plant retirements, and that accelerating depletion of nuclear generation depreciation reserves is inappropriate given the Company's very recent investments in these plants.[270] These conclusions remain accurate, and should continue to control the outcome of this issue. In short, the Company's calculations best account for the nuclear generation plant theoretical reserve, for recent nuclear investments, and for the current operating life and retirement needs of these facilities without risking greater burden on future customers.

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[269] XLI Initial Brief at 7.

[270] ORDER at 27 and 29, Docket No. E002/GR-12-961.

Second, XLI suggests that "none of the parties addressing this issue in testimony provided analysis disputing the existence of a surplus."[271] This overstates the Parties' positions. As noted at the hearing and in the Company's initial brief, the Company's present estimate of a surplus nuclear theoretical reserve does not indicate that excess funds will exist over the long term.[272] Unlike a transmission, distribution, and general theoretical reserve, which is determined on the basis of a large number of individual assets, the nuclear theoretical reserve consists of a limited number of plants with finite lives.[273] Thus "the 'surplus' is only an estimate, not a guaranteed surplus."[274]

Third, XLI argues that the Company's present estimate calculation is incorrect because (i) depreciation relates to already-invested capital and therefore should not incorporate future nuclear investment; and (ii) it assumes the Company will retire its nuclear facilities at the end of their current operating licenses. With respect to the consideration of future nuclear investments, the Company does not and does not incorporate the need for future capital additions in the calculation of depreciation expense and does not suggest that it should build a surplus reserve solely to account for future capital additions.[275] Rather, the purpose of considering future investments is to provide a realistic view of depreciation expense over the remaining life of each plant.[276] XLI's calculation ignores this consideration.

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271 XLI Initial Brief at 6.

272 Company Initial Brief at p. 100; Tr. Vol. 2 at 67 (Perkett) ("Q: So we're not disputing that an actual surplus exists?" "A. I would disagree with that. The Company believes that the surplus that you have calculated or any calculation is not necessarily a real number; it is a mathematical calculation. To the extent that there is a reserve ahead or behind where it should be according to a match calculation, it's – again, it's just a gauge. It's not necessarily a hard or firm surplus.").

273 Ex. 92, Perkett Direct at 49.

274 Ex. 434, Campbell Rebuttal at 2.

275 Ex. 94, Perkett Rebuttal at 10.

276 Ex. 94, Perkett Rebuttal at 10; Ex. 434, Campbell Rebuttal at 3.

Finally, XLI notes that "further life extensions [of the Company's nuclear facilities] likely would have the effect of increasing the present surplus" and that "future extensions seem plausible given impending federal greenhouse gas regulations."[277] The Company agrees that extending the operating license of the Company's nuclear plants is plausible, but does not agree that this possibility warrants amortizing an estimated nuclear theoretical reserve surplus over a shorter, 5-year period and placing a larger burden on future customers to re-collect that surplus. If the Parties and the Commission concur that the Company's nuclear plant licenses are highly likely to be extended, the more appropriate way to reduce the present revenue requirement is to extend the useful life of the plants beyond their current license period.[278] Under present circumstances, the Company recommends against XLI's proposal with respect to the nuclear theoretical reserve.

E. Changes to In-Service Dates for Capital Projects (2014 and 2015 Step)

The Department's proposed $2.18 million adjustment for changes of in-service dates is inconsistent with the test year concept and should be rejected on that basis.[279] The Company has demonstrated the representativeness of its test year capital budget,[280] and therefore respectfully requests the ALJ and the Commission to approve it. Notwithstanding the reasonableness and representativeness of the Company's test year's capital budget, the Department is proposing several adjustments that, when taken to their logical extension, create tension with the Company's ability to manage its business and obtain recovery of capital investments that support our ability to provide electricity today and into the future.

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277 XLI Initial Brief at 7 (emphasis added).
278 Tr. Vol. 2 at 57 (Perkett).
279 Company Initial Brief at pp. 103-105.
280 *See generally* Ex. 51, O'Connor Direct; Ex. 62 Harkness Direct; Ex. 58, Mills Direct; Ex. 65 Kline Direct; Ex. 69 Foss Direct; Ex. 86 Stitt Direct.

Managing capital budgets while making allowances for changing business conditions is a fundamental component of our ability to prudently manage our business. As discussed by our core operations witnesses, there are not sufficient capital funds available to implement every capital project that our core operations require.[281] Instead, the Company must prioritize its capital spending and address the most urgent needs first while determining what other capital projects can be deferred for later years.[282] The Company has instituted a rigorous capital budgeting process to enable this prioritization.[283]

However, the reality of our operations do not always match our forecasted needs. We may implement a like kind replacement when one budgeted project is determined to not be as urgent as a different similar project.[284] Or, we may have other work emerge that becomes more urgent to address and therefore requires we postpone a budgeted capital project to free up capital funds to meet these emergent needs.[285] And, normal business changes can also affect our capital priorities and we need to respond to these events in real time.[286] These types of changes happen throughout the year and after our budgets are finalized. Managing our capital budgets as the test year becomes an actual year, while continuing to provide safe and reliable service, is a hallmark of prudent utility management.

Company Witness Mr. Steven Mills provides a historic example of this prudent management of our capital budgets:

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281 *See generally* Ex. 51, O'Connor Direct at pp. 14-79; Ex. 62 Harkness Direct at pp. 16-56; Ex. 58, Mills Direct at pp. 40-66; Ex. 65 Kline Direct at pp. 37-74; Ex. 69, Foss Direct at pp. 27-48; Ex. 86 Stitt Direct at pp. 4-22.

282 *See generally* Ex. 51, O'Connor Direct at pp. 14-79; Ex. 62 Harkness Direct at pp. 16-56; Ex. 58, Mills Direct at pp. 40-66; Ex. 65 Kline Direct at pp. 37-74; Ex. 69, Foss Direct at pp. 27-48; Ex. 86 Stitt Direct at pp. 4-22.

283 Ex. 86, Stitt Direct at pp. 19-22.

284 Ex. 94, Perkett Rebuttal at Schedule 11.

285 Ex. 94, Perkett Rebuttal at Schedule 11.

286 Ex. 94, Perkett Rebuttal at Schedule 11.

> In 2013 we identified some unbudgeted emergent needs. These include the need to replace the High Bridge Unit 7 combustion turbine expansion joints since the expansion joints were leaking. Further we identified the need to rewind the Sherco Unit 3 circulation pump motor to help ensure the reliable operation of the plant after its Restoration.
>
> We identified funds to meet these emergent needs by delaying other capital projects and identifying interim solutions. More specifically, we had budgeted to replace the boiler steam drum supports at Red Wing Units 1 and 2 since the existing drum support I-beams were tilted. Instead, we added stiffening rods to support the drum instead of replacing the support in 2013. By delaying this work, we were able to address these emergent needs and mitigate impacts to our capital budget.[287]

Mr. Mills' example also demonstrates how the Company must react to circumstances in real time to maintain reliable service. Joint leaks must be responded to and creative interim solutions to other capital needs allow us to respond to these events within our budget.

The Department's in-service date adjustment would discourage this type of active management by shifting the financial risk of undertaking capital projects, that are reprioritized or are not in a test year, to the Company. The Department asserts that the Company "apparently was unable to reasonably manage changes in capital project in-service dates for the purpose of the rate case."[288] However, the Company does not manage its capital project in-service dates for purposes of a rate case. Instead, the Company manages its in-service dates for the provision of safe and reliable service. We believe this is the more appropriate path as it provides us the

[287] Ex. 60, Mills Rebuttal at p. 20.
[288] Department Initial Brief at p. 122.

flexibility to operate our business, which includes responding to events that cannot be foreseen on a year-to-year basis (i.e., natural disasters).

Additionally, the record reflects that the Company manages to its capital budget in a reasonable manner.[289] As Mr. Mills' example shows, a capital project was delayed and an interim solution was devised to free up capital funds to address an emergent need. In other words, the outcome was intended to have no net effect to the amount of capital placed in-service in the particular year, either above or below budget. Consequently, the Department's observation that "project examples suggested that capital costs appear to be more likely to go down rather than up during Xcel's test-years"[290] is not supported.

Ultimately, the test year concept is sufficiently flexible to address our day-in, day-out needs to manage the Company and acknowledges that changes will occur but will likely balance themselves out: "… isolated changes in test year data can skew the rate case process …. Not adjusting for either type of change [up or down] maintains this symmetry and maintains the integrity of the test year process."[291]

F. Interest Rate on Interim Rate Refund

The OAG recommends that the interest rate on any interim rate refund be paid at the Company's overall rate of return (ROR), quoting extensively from the Commission's order in our last rate case (the 12-961 Order). As the Company explained in its initial brief, there are material differences between this rate case and the last rate case such that there is no need to deviate from providing any interim rate refund with an interest rate equal to the prime rate. Thus, the Company respectfully requests the Commission and ALJ reject this recommendation.

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[289] Ex. 86, Stitt Direct at pp. 4-22.

[290] Department Initial Brief at pp. 122.

[291] *In the Matter of the Complaint by Myer Shark et. al. Regarding Xcel Energy's Income Taxes*, Docket No. E, G 002/C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at p. 4 (Oct. 1, 2004).

The OAG cites the "magnitude and frequency of Xcel's rate requests" and asserts that we have requested the "largest rate increase in the history of the state" to support its recommendation. [292] The 12-961 Order noted that the Company has much greater control than ratepayers "over whether, when, and how much ratepayers must borrow from or lend to the utility."[293] The Company submits that: (1) the scale of its investments have driven the timing and scale of its rate increase requests, neither of which are suspect or support a variance; and (2) the Company significantly mitigated its interim rate increase in this case.

The timing and size of the Company's requested rate increases are directly related to the scale of the Company's investments, which are also the largest in Minnesota history. The Company invested approximately $7.6 billion between 2005 and 2012 and is projected to invest an additional $6.0 billion by 2017.[294] Investments of this scale require rate support, and there is no basis to assume a large rate request has any significance on the merits, much less that a large request is inherently suspect.

The Company determines when and how to file rate increase requests (including interim rate requests). However, making investments without seeking the earnings needed to support those investments is not a decision the Company can reasonably be expected to make. Accordingly, the Company should not be faulted for requesting rate increases needed to support those investments.

The OAG also fails to recognize that the Company took a conservative approach to interim rates in this case, as noted in the Company's Initial Brief and in its Interim Rate Petition.[295] Specifically, the Company's requested interim rates reflect $81.5 million in rate mitigation, based on the Company's proposed 50-30-20

[292] OAG Initial Brief at 42.
[293] E002/GR-12-961 ORDER at 38.
[294] Ex. 30, Tyson Direct at 5, 15-16.
[295] Company Initial Brief at 106.

amortization of a theoretical depreciation reserve schedule, instead of using the existing 8-year amortization schedule.[296] Since there was no assurance that the Company's proposal would be accepted, the Company was at risk for an interim deficiency. The Company would not take this approach if it was attempting to maximize short run revenues, as the OAG infers.

The OAG also argues that it is unfair to provide the Company "low cost funds from ratepayers" which imposes "an excessive burden on ratepayers."[297] The 12-961 Order refers to ratepayers "as captive lenders", and concludes that using the Company's overall rate of return "equitably compensates ratepayers for forgone opportunities … without penalizing the Company relative to its average cost to obtain funds in the market."[298] The Company respectfully disagrees with these conclusions.

The 3.25 percent Prime Rate on interim rate refunds is substantially higher than the Company's 0.62 percent cost of short-term debt (a fact that is undisputed), which means that the Company is not obtaining any advantage.[299] The Prime Rate is also substantially higher than customers can earn for any short term lending. Customers could not obtain interest on a fully secure short-term loan (0 to 21 months) at a rate even close to the ROR, which is over 7.00 percent under both the Company's and Department's recommendations. Further, applying "the average cost to obtain funds in the market" does impose a penalty on the Company because the short term interim revenues (available for 0 to 21 months) are not a substitute for <u>all sources of funds</u> (long term debt and equity), but substitute only for <u>short-term borrowing</u>.

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[296] Interim Rate Petition at 7-8.

[297] OAG Initial Brief at 42.

[298] E002/GR-12-961 ORDER at 38-39.

[299] Company Initial Brief at 106; Ex. 31, Tyson Rebuttal at 23-24 ("Interim rate revenues are generally available for a period of time that is one year or less. As a result, interim rate revenues are considered a short-term resource … . The short-term resource provided by interim rate revenues decreases our need for other short-term financing that would otherwise be required … .").

The 12-961 Order also cited "historically low levels" of the Prime Rate as a source of excess burden to customers.[300] However, ratepayers are benefiting from historically low interest rates through the Company's recent borrowing costs. Since 2010, the Company has issued 5-year debt at 1.95 percent; 10-year debt at 2.15 percent and 2.60 percent; and 30-year debt at 4.12 percent and 4.85 percent.[301] These rates both benefit customers and show that a 3.25 percent rate for short-term use of interim rate revenues is already quite high.

The 12-961 Order also noted concerns about impacts on low-income customers.[302] The Company respects this concern, but concern for impacts on low-income customers does not support an across-the-board adjustment that applies to all customers and imposes a financial penalty on the Company. Rather, if the Commission believes that impact on low-income customers merits a variance, the variance should be limited to those customers. Low-income program information could be used to direct adjusted interest rates to those customers.

Finally, the OAG's argument is also at odds with Minnesota's broad pattern of using short term borrowing rates as the interest rates for customer repayments, including interim rate refunds, customer overcharges and customer deposits.[303]

G. Fuel Clause Adjustment Incentive (FCA)/Sherco 3 Fuel Costs

Both the Company and the Department agree that issues related to the Company's Fuel Clause Adjustment (FCA) and Sherco 3 Fuel replacement costs are most properly addressed in the Annual Automatic Adjustment (AAA) proceeding. Importantly, the Department notes that any changes to the Company's Fuel Clause

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[300] E002/GR-12-961 ORDER at 38.

[301] Ex. 31, Tyson Rebuttal, Schedule 6.

[302] E002/GR-12-961 ORDER at 38.

[303] Minn. Rule 7820.3800, subp. 2 ("Interest must be calculated as prescribed by Minnesota Statutes, section 325E.02, paragraph (b)."); Minn. Stat. § 325E.02(b)("The rate of interest must be set annually and be equal to the weekly average yield of one-year United States Treasury securities …") which is currently 0.126 percent. *See* http://mn.gov/commerce/energy/topics/resources/Reports-Data/Deposit-Interest-Rates-Utilities.jsp

Adjustment could implicate other utilities[304] and therefore this rate case is not an appropriate forum with which to address parties' interest in Fuel Clause reform.

The Company agrees that FCA reform may be appropriate.[305] However, given the wide-ranging implications FCA reform may have, the Company concurs with the Department that it is more appropriate to address it in a dedicated proceeding such as the AAA. Consequently, the Company respectfully requests the Commission and ALJ reject XLI's request to require the Company to submit a fuel clause incentive proposal as part of this proceeding.[306]

Similarly, the issue of replacement fuel costs due to the extended outage at Sherco 3 are best addressed in an AAA proceeding. In fact, the Chamber appears to agree that adjustments to the Company's FCA should be made in the AAA proceeding.[307] Consequently, the Company recommends that the ALJ and Commission utilize an AAA proceeding to address issues regarding Sherco 3 replacement fuel.

H. Corporate Aviation

The Company's request to recover half of its corporate aviation costs is reasonable, justified and consistent with Commission precedent.[308] Further, by only seeking to recover half of our aviation costs, the Company believes that all of the issues raised by the OAG are subsumed into this Company proposed adjustment. While the OAG may view this adjustment as a "blunt tool"[309] it is nevertheless an effective tool that has been accepted by the Commission. Simply put, we believe our

[304] Ex. 412, Ouanes Rebuttal at 15.
[305] Ex. 100, Clark Rebuttal at 43.
[306] XLI Initial Brief at p. 11-12.
[307] MCC Initial Brief at p. 6 (requesting an adjustment for Sherco 3 replacement fuel be ordered in the AAA proceeding).
[308] Company Initial Brief at pp. 108-109.
[309] OAG Initial Brief at p. 24.

request addresses current and historic concerns while allowing the Company to recover a portion of this reasonable cost of service.

1. The Company Has Provided All Required Information

In its initial brief, the OAG argues that the Company has failed to meet the "Commission's requirement to provide more information."[310] Without really specifying what that "more information" is, the OAG cites the following order point in support of its contention:

> In the initial filing of its next rate case, the Company shall include more detailed flight data reports (preferably in live Microsoft Excel electronic format) of its corporate jet trip logs for its most recent 12-month operational period. The report, by flight, must identify the charged employee, each employee passenger and his/her assigned operating company, the other passengers on flight and reason for use, and primary purpose for scheduling the flight. The Company shall include information for the calculation of the requested recovery amount of corporate aviation.[311]

The evidence on the record demonstrates that the Company has complied with the filing requirements set by the Commission in our previous rate case. All of the required information was provided as schedules to Mr. Gary O'Hara's Direct Testimony: (1) Schedule 11 provides information with respect to charging of corporate aviation costs; (2) Schedule 12 provides the required flight log; and (3) Schedule 13 provides information calculating the Company's request for corporate aviation costs in this rate case.

In closing, we note that there appears to be concern from the OAG that the business purposes provided in our flight logs are not detailed enough.[312] While we

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[310] OAG Initial Brief at p. 23.

[311] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961, FINDINGS OF FACT, CONCLUSIONS AND ORDER (Sept. 3, 2013) at Order Point 53.

[312] OAG Initial Brief at p. 23.

disagree with the OAG, it is important to keep in mind that our obligation to provide information about our corporate aviation services arises from Minn. Stat. §216B.16, subd. 17 ("Employee Expense Statute"). The Employee Expense Statute requires the Company to provide expenses related to owned, leased, or chartered aircraft.[313] The Company is allowed to use our standard accounting reports to meet our obligations, which is exactly what we did here.[314] If the Commission or ALJ prefers that we elevate the detail of our current reporting systems, we can begin the analysis of the technical requirements and costs associated with doing so and report the results with our next rate case.

2. Corporate Aviation Supports the Provision of Service

Our corporate aircraft do not fly without a valid business purpose.[315] This is a fundamental requirement of the Company's policy for use of corporate aviation.[316] Consequently, the Company requires corporate aviation services are used only for a valid business purpose. The OAG has not demonstrated otherwise.

The OAG incorrectly assumes that flights coded as for "Personal Travel" do not have a valid business purpose. Rather the "only time the Personal Travel code is used is for the rare occasion when spouses of Company executive employees or members of the Xcel Energy Board of Directors accompany them to attend Company business functions."[317] This type of activity is usually in the furtherance of "promot[ing] the public image of the [C]ompany or to cultivate business relationships."[318] These are reasonable activities in furtherance of the Company's

[313] Minn. Stat. § 216B.16, subd. 17(a)(8).
[314] Minn. Stat. § 216B.16, subd. 17(b).
[315] Ex. 77, O'Hara Rebuttal at p. 7 ("[t]he prerequisite for scheduling a Company aircraft flight is a valid business purpose").
[316] Ex. 77, O'Hara Rebuttal at p. 7.
[317] Ex. 77, O'Hara Rebuttal at p. 8.
[318] Ex. 77, O'Hara Rebuttal at p. 8.

long-term goals to provide safe and reliable service. That said, we note that less than one percent of all use of the corporate aircraft was coded as Personal Travel and that therefore, should any adjustment need to be made it would be subsumed in the 50 percent initial adjustment proposed by the Company.[319]

Additionally, the OAG appears to believe that use of the corporate aircraft for Investor Relations is not in support of the provision of service.[320] This is incorrect. "Minnesota law requires Xcel Energy to organize an annual shareholders' meeting. We also need to cultivate investor relations in order to have access to publicly held debt and equity capital. These are reasonable and necessary functions that are needed to conduct our day-to-day business."[321] That said, we note "[a]bout 10 percent of corporate aviation costs are allocated to the Xcel Energy Inc. holding company. As noted above, we are only requesting recovery for 50 percent of the corporate aviation costs allocated to the Minnesota electric jurisdiction."[322] Consequently, the OAG's concerns have been addressed through the Company's request.

Last, the OAG proposed to disallow the costs of 42 flights for which the business purpose was listed as "Aviation Use."[323] This is similarly misplaced. At base, Aviation Use flights "are necessary to maintain the functionality of the aircraft and provide corporate aviation services."[324] Consequently, these are costs that are necessary to allow the use of the corporate aircraft to support the provision of service and are therefore appropriate to include in rates.

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[319] Ex. 77, O'Hara Rebuttal at p. 8.
[320] OAG Initial Brief at 23-24.
[321] Ex. 77, O'Hara Rebuttal at pp. 10-11.
[322] Ex. 77, O'Hara Rebuttal at p. 11.
[323] OAG Initial Brief at p. 24.
[324] Ex. 77, O'Hara Rebuttal at p. 11.

3. Costs of Corporate Aviation are Reasonable

The OAG proffers that the only reasonable cost for a flight from Minneapolis to Denver is $300 and proposes to adjust the Company's aviation costs to reflect this amount.[325] This calculation is outdated,[326] inaccurate and neglects the full benefits of the Company's use of corporate aircraft. Consequently, the OAG's $300 cost cap on use of corporate aviation should be rejected.

The Company does not agree with "Mr. Lindell's methodology to establish a price for one-way ticket and to multiply the ticket price by the number of passengers. His approach does not take into account practical issues that affect ticket prices, such as flights to various locations, different time periods between reservation and travel and fees related to ticket changes or cancellations."[327]

Most importantly, this methodology "does not account for increased productivity, time savings, avoided hotel charges, or any other benefits of corporate aviation."[328] These benefits are well documented and reflected in the record.[329] The Aviation Study provided by the Company identified the "benefits associated with employee time savings and increased productivity."[330] The results of the Aviation Study identified that a majority of the Company's corporate aviation expenses were "justified compared to commercial aviation services."[331] Additionally, the Minnesota Department of Transportation has identified many ancillary benefits of corporate aviation including "increased individual and group productivity, privacy during flights,

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[325] Ex. 370, Lindell Direct at p. 50.
[326] Ex. 370, Lindell Direct at p. 50 (utilizing 2010 information).
[327] Ex. 77, O'Hara Rebuttal at p. 7.
[328] Ex. 77, O'Hara Rebuttal at p. 7.
[329] Ex. 75, O'Hara Direct at Schedule 12.
[330] Ex. 77, O'Hara Rebuttal at p. 4.
[331] Ex. 77, O'Hara Rebuttal at p. 4.

safety, flexible scheduling, reduced travel expenses, and time savings."[332] The OAG's use of commercial aviation costs as a proxy does not take into consideration the value ratepayers receive from corporate aviation and should be rejected.

4. The Company has Reasonable Controls In Place

It is Company policy that the corporate aircraft may only be used for business purposes.[333] Additionally, the corporate aircraft may only be authorized for use by employees of the rank Vice President or higher.[334] These are high-ranking employees who are responsible for the overall management of the Company. It is expected that they comply with all Company policies as they are also the employees responsible for enforcing Company policies. This results in a strong control that ensures corporate aircraft are appropriately used. This is borne out by a review of the flight logs that show the overwhelming majority of flights on the corporate aircraft are between city pairs where the Company has operations with the vast majority of flights between Denver and Minneapolis, the Company's two core areas of operation.[335] Consequently, the OAG's concerns are not valid and should be rejected. Additionally, even if the corporate aircraft was not used for a valid business purpose on rare occasions, the Company's proposed 50 percent adjustment would address the OAG's concerns.

I. Rate Case and Monticello Prudency Review Expense Amortization

The Company and the Department have resolved the disposition of the amortization of the Company's rate case expenses for this case.[336] The Company and the Department continue to dispute the appropriate treatment of the approximately $950,000 for the cost of conducting the Monticello prudence investigation. The

[332] Ex. 77, O'Hara Rebuttal at p. 4 (citing to http://dotapp7.dot.state.mn.us/flyordrive/about.vm).
[333] Ex. 75, O'Hara Direct at Schedule 2.
[334] Ex. 75, O'Hara Direct At Schedule 2.
[335] Ex. 75, O'Hara Direct at Schedule 12.
[336] Department Initial Brief at p. 127.

Company proposed to amortize these costs over two years, consistent with the likelihood the Company file its next rate case in late 2015.[337] The Department proposes to amortize the costs of Monticello prudence review over the remaining life of the Monticello plant.[338]

The Department essentially argues that their proposal will allow a "sharing of these costs between ratepayers and shareholders; ratepayers would pay the Company back for the prudency review costs over the life of the facility, and shareholders would recover the costs of the review but not earn a return on it."[339] However, the Department's proposal is asymmetrical because amortizing the costs of the Monticello prudence review over the life of the plant does not allow shareholders to recover all of their costs due to the time value of money. Without a carrying charge, shareholders are not made whole as the Department argues.[340] While the Company is not proposing a carrying charge, the shorter amortization period proposed by the Company would not degrade the recovery of these costs over the much longer amortization period proposed by the Department. To the extent that the Department's proposal is supposed to balance the interest of ratepayers and shareholders, the Company's proposed two-year amortization schedule better meets this intent.

J. Nuclear Refueling Outage Costs – Accounting Methodology

The OAG argues that the Company should not earn a return on the unamortized balance of nuclear refueling outage costs,[341] and that the Company's

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[337] Ex. 90, Heuer Rebuttal at p. 24.
[338] Lusti Surrebuttal at pp. 17-18.
[339] Department Initial Brief at p. 130.
[340] Ex. 90 Heuer Rebuttal at p. 24.
[341] OAG Initial Brief at 28-29.

2015 Step revenue requirement should be reduced by $5.5 million for nuclear refueling outage expenses.[342] Neither recommendation should be accepted.

1. Allowing the ROR on unamortized nuclear refueling outage costs remains appropriate.

The OAG cites the ALJ recommendation in our last rate case to reduce the rate applied to the ROR to unamortized nuclear refueling outage costs.[343] However, the Commission did not accept that recommendation, much less to eliminate any return, as the OAG recommended in both that case and in this case.

In our last rate case, the Commission recognized the need for a full return, the importance of the time period of the amortization, and the importance of consistent treatment of the unamortized balances of Company and customer prepayments, saying:

> The 18- to 24-month period over which these costs are normally amortized exceeds normal short-term-debt time frames, and the Company's 0.68% cost of short-term debt would not adequately compensate the Company or its ratepayers for this use of capital. Further, the Company credits ratepayers at the rate of return when amortized amounts exceed actual costs, ensuring equitable treatment.[344]

These same factors are present in this case. The period of amortization is no shorter,[345] and the Company's cost of short-term debt is now 0.62 percent, making a short-term debt return even more inadequate. There is also no evidence that the Company does not incur its full ROR in financing prepayments that remain uncollected for 18 to 24 months. Further, the Company also reduces rate base for any balances of customer expense prepayment, resulting in a credit equal to the ROR and

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342 OAG Initial Brief at 29-31.

343 OAG Initial Brief at 29.

344 E-002/GR-12-961 ORDER at 40-41.

345 Ex. 97, Robinson Rebuttal at 22.

ensuring equitable and symmetrical treatment of both ratepayer and Company prepayments.

The OAG also claims that the Company lacks incentives to keep costs low, based on a comparison of nuclear fuel expense increases to general O&M expenses trends.[346] To the contrary, the Company: (1) uses its best efforts to estimate costs as accurately as possible; and (2) has an ongoing obligation to show that its nuclear refueling outage costs are reasonable and accurate.[347] Further, the comparison of a unique cost, such as nuclear refueling, to routine O&M expenses has no analytic or probative value.

The OAG's recommendation should be rejected as it was in our last rate case.

2. No adjustment should be made to the 2015 Step year for nuclear refueling outage costs, as the Department recognized.

The Department recognized that nuclear refueling outage costs were not related to 2015 capital projects and thus withdrew its recommendation for an adjustment to the 2015 Step year.[348] In contrast, the OAG continues to recommend a $5.5 million reduction in the 2015 Step year. However, none of the OAG's arguments support its recommendation.

The OAG continues to argue that nuclear refueling costs are "related to capital projects" and are "related to capital investments" and likens nuclear refueling costs to depreciation.[349] Contrary to the OAG arguments, nuclear refueling amortization is not related to capital investments and nuclear refueling amortization costs are no more closely related to capital investment than routine maintenance expenses, none of which are included in the 2015 Step.

[346] OAG Initial Brief at 29.

[347] Ex. 97, Robinson Rebuttal at 24

[348] Ex. 450, Campbell Opening Statement at 1; Company Initial Brief at 112.

[349] OAG Initial Brief at 30

The OAG's reference to treating the return on the unamortized nuclear refueling balance as "a return on rate base"[350] has no significance. The transcript of the testimony cited by the OAG makes it clear that the witnesses answer simply meant that the unamortized balance was "contained within rate base."[351] This is not significant to treatment in the 2015 Step because inclusion in rate base is simply the standard ratemaking treatment for Company prepaid balances (which are included in rate base) and customer prepaid balances (which reduce rate base). The inclusion of unamortized balances in rate base has no relation to capital additions, which is the requirement for a consistent approach to the 2015 Step year revenue requirement.
Finally, the OAG's reliance on Ms. Campbell's position in her Direct Testimony[352] is a mischaracterization of her position, since Ms. Campbell clearly stated that her initial position had been based on the mistaken belief that the nuclear amortization balance was related to capital additions.[353] Such an argument clearly does not support any adjustment, much less a $5.5 million adjust

K. Black Dog 5/2

No party has briefed this issue and the Company relies on its discussion in its Initial Brief to support the rejection of XLI's proposed adjustment.[354]

L. Capital Structure, and Costs of Short Term Debt and Long Term Debt

The Department supported the use of Company's actual updated capital structure and costs of Long Term Debt (LTD) and Short Term Debt (STD) for both the 2014 test year[355] and the 2015 Step year.[356] The updated 2014 test year and 2015 Step year Capital Structure and costs of LTD and STD are as follows:

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[350] OAG Initial Brief at 31.
[351] Tr. Vol 2 at 101, line 8-13(Robinson)
[352] OAG Initial Brief at 31.
[353] Ex. 450, Campbell Opening Statement at 1.
[354] Company Initial Brief at pp. 114-117.
[355] Department Initial Brief at 41-42.

Updated 2014 test year

	Percent of Total Capitalization	Cost
Long Term Debt	45.60%	4.90%
Short Term Debt	1.90%	0.62%
Common Equity	52.50%	
Total	100.00%	

Updated 2015 Step year

	Percent of Total Capitalization	Cost
Long Term Debt	45.61%	4.94%
Short Term Debt	1.89%	1.12%
Common Equity	52.50%	
Total	100.00%	

The ICI Group recommended that the percentage of common equity be set at 47.5 percent for the 2014 test year and 49.0 percent for the 2015 Step year.[357] ICI Group's recommendation for not using the Company's actual 52.5 percent equity ratio is based on ICI Group's belief that: "Northern States Power is an accounting fiction as it is simply an entry on the books of Xcel Energy, Inc."[358]

The ICI Group is completely mistaken. As the Company demonstrated: (1) the Company is a separate legal entity from its parent, Xcel Energy, Inc. (XEI) and not simply an internal accounting structure; (2) the Company's actual capital structure provides the direct financial support for the Company's separate debt ratings and for the Company's $3.9 billion of outstanding publicly traded LTD securities; (3) the Company's separate capital structure is regularly reported to the Securities and Exchange Commission in filings related to the Company's publicly traded LTD; (4)

[356] Department Initial Brief at 44-45.

[357] ICI Group Initial Brief at 15.

[358] ICI Group Initial Brief at 15-16.

the Company's equity ratio is needed to support its current debt ratings; and (5) the Company's actual capital structure is reasonable in comparison to other utilities.[359] The Department recognized the Company's separate legal existence, its separate debt and debt ratings, and the reasonableness of the equity ratio and supported the use of the Company's actual capital structures for both the 2014 test year and the 2015 Step year.[360]

The ICI Group's recommendation is based on a completely erroneous belief and lacks any other support. Accordingly, it should be rejected.

M. FERC Cost Comparison Study- KPI Benchmarks

The Company continues to believe that that the use of FERC Cost Comparison Study is not appropriate for benchmarking the Company's performance as the Study does not allow the Company to draw reasoned conclusions as to why it ranks as it does against it peers. Without this information, it is impossible for the Company to analyze its deficiencies and therefore implement improvements. For this reason, the Company does not believe utilization of the FERC Cost Comparison Study for the purposes offered by the MCC is appropriate.

With that said, the Company continually works to improve its performance. In light of its non-fuel O&M performance in the FERC Cost Comparison Study, the Company has implemented a non-fuel O&M KPI to a more reasonable metric with which to hold our employees accountable. We believe that this significantly addresses the Chamber's concerns. Additionally, the Company has offered to work with the Chamber to develop a reasonable KPI metric with respect to transmission costs that will eliminate the concerns with respect to the comparison group or with the metrics measured. We believe doing so would be a more effective way to measure, and where

[359] Company Initial Brief at 118; Ex. 30, Tyson Direct at 9; Ex. 31, Tyson Rebuttal at 4-7; Ex. 27, Hevert Direct at 53.
[360] Department Initial Brief at 36-38, 42.

necessary improve, our performance in this area than with the blunt and less useful tool of the FERC Cost Comparison Study.

N. Transmission Cost Controls

The Company appreciates the MCC's clarification as to its recommendation, limiting such recommendation to a request that "Xcel … create a Key Performance Incentive for the Transmission Vice President, which would drive appropriate management of costs at a high level for the Company and ratepayers."[361] The Company will respond to this recommendation in this Reply and rests on its Initial Brief in response to other issues related to the Transmission Business Area raised by the MCC on the record in this proceeding.

The record demonstrates that the Xcel Energy Vice President, Transmission is ultimately responsible to Xcel Energy senior management for the implementation of transmission projects, including keep these projects reasonably on budget.[362] The Transmission Business area measures its performance of implementing transmission projects on budget monthly and, in the last three years has been performing within 1.5 percent of its total budget.[363] The Company has demonstrated that it constantly monitors its capital spending in the Transmission Business Area and is reasonably on budget. The ultimate responsibility for this lies with the Vice President, Transmission.[364] Consequently, the Company does not believe an additional KPI is required to hold the Vice President, Transmission responsible for its responsibilities, and the Vice President, Transmission is performing within a reasonable bound with respect to capital spending.

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[361] MCC Initial Brief at p. 8.
[362] Ex. 67, Kline Rebuttal at p. 26 and Schedule 5.
[363] Ex. 65, Kline Direct at pp. 47-48.
[364] Ex. 67, Kline Rebuttal at p. 26.

V. RESOLVED ISSUES

As the Company indicated in its Initial Brief, there are quite a few issues that have been resolved between the Company and Department. The Company appreciates the Department's willingness to work towards reasonable resolutions of the issues involving only the Department and Company. While the Company is not providing a recitation of the record, the Company believes the record supports each one.

With that said, there are two resolutions – sales forecast and property tax – that take advantage of the unique circumstances presented by this case. Specifically, the length of this case allows for the use of actual sales data to establish test year revenues, and actual property tax expense to establish property tax expense for the test year. By using actual data for sales and property taxes, final rates will include the most accurate information which is beneficial for our customers, especially considering the Company has proposed a MYRP.

With that said, we recognize the Commission or ALJ may want to continue using forecasted information for establishing sales and property taxes in the test year. As a result, we explain below the reasons supporting the use of our sales and property tax forecasts should the resolutions reached regarding these issues not be accepted.

A. Sales Forecast

We share with our customers the goal of having a sales forecast that predicts test year sales as accurately as possible. An accurate sales forecast provides the Company a reasonable opportunity to recover its costs of service and ensures that the rates customers pay closely reflect the cost the utility incurs to provide electric service.

The timing of the current case allows for the use of actual data for purposes of setting rates in this proceeding. The Department and the Company, the only two parties providing a sales forecast in this case, agree that the use of weather-normalized actual 2014 sales, with an adjustment for the known change to the large commercial and industrial class, is appropriate in this case.[365] In addition, while not providing a full sales forecast for the case, the Chamber provided testimony regarding the effect of energy efficiency on sales.[366] The Chamber also supports the use of weather-normalized actual 2014 sales in this proceeding.[367] Finally, the Company and the Department further agreed to use the Department's coefficients for purposes of the weather-normalization calculation.[368]

In her Opening Statement, Company witness Ms. Anne Heuer explained the Company's proposal to provide actual data through November by December 16, 2014, to provide parties an opportunity to review the information prior to the due date for the ALJ's Report.[369] The Company proposed to submit actual sales for all of 2014 by January 16, 2015.[370] While the January date was closer in time to the Commission's anticipated deliberations on the case, parties would have only one additional month of data to review in the January 2015 timeframe.[371] Although the Company offered to submit forecasted December sales as an alternative, the Company, the Department and the Chamber agree that actual 2014 sales should be used.[372]

If the Commission does not adopt the recommendation to use actual sales, the Commission should apply the Company's rebuttal sales forecast for purposes of setting rates. The Company's forecast is supported by the evidence in the record, is

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[365] Tr. Vol. 4 at 55 (Shah). The Chamber also filed testimony on the effect of energy efficiency on the forecast. Ex. 343, Maini Direct at 6-8. The Chamber also supports the use of weather-normalized actual 2014 sales for purposes of setting rates in this proceeding. Tr. Vol. 4 at 13 (Maini).

[366] Ex. 343 Maini Direct at 6-8.

[367] Tr. Vol. 4 at 13 (Maini).

[368] Tr. Vol. 1 at 169 (Hyde)

[369] Ex. 140, Heuer Opening Statement at 5.

[370] Ex. 140, Heuer Opening Statement at 5.

[371] Ex. 140, Heuer Opening Statement at 5.

[372] Ex. 140, Heuer Opening Statement at 5.

demonstrated to be more accurate than the Department's forecast, and produces results shown to be reasonable.

1. Actual Sales

The sales forecast issues disputed between the parties are largely the same issues raised in the last Minnesota electric rate case, Docket No. E002/GR-12-961, including the price variable and the use of the DSM adjustment. The adjustment for DSM savings has continued to be the sales forecast issue of greatest disagreement between the parties. Use of actual sales resolves these disputes for purposes of the current case.

In the last case, the Commission adopted the Department's forecast which did not address the savings related to energy efficiency.[373] As explained by Company witness Ms. Jannell Marks, weather-normalized actual 2013 sales were significantly lower than the forecast approved by the Commission in the last case.[374] Weather-normalized actual 2013 sales were 0.3% higher than the Company's forecast.[375] In this case, in order to avoid the significant under-recovery of a forecast set to high, or an over-recovery if the forecast were set too low, the parties have agreed to use actual sales.

2. Company Forecast

The Company provided an updated forecast in the Rebuttal Testimony of Company Witness Ms. Jannell Marks reflecting the use of actual data through the end of May 2014. [376] The record supports the use of the Company's rebuttal forecast for purposes of setting rates in this case if the Commission declines to adopt the proposal to use weather-normalized actual sales.

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[373] FINDINGS OF FACT, CONCLUSIONS AND ORDER at 30, Docket No. E002/GR-12-961 (September 3, 2013).
[374] Ex. 38, Marks Direct at 18.
[375] Ex. 40 Marks Rebuttal at 8.
[376] Ex. 40 Marks Rebuttal.

3. DSM Adjustment

DSM achievements have contributed to lower sales growth over the last several years.[377] And, although the Commission declined to adopt a sales forecast addressing DSM savings in the last case, energy efficiency savings continue to impact the sales forecast going forward. As reflected in Ms. Marks' testimony, the continued impact of embedded DSM is significantly lower than the impact of future DSM savings.[378]

In response to the issues raised in the last case, and recognizing that energy efficiency savings continue to impact the sales forecast in this case, the Company proposed a new methodology to account for future DSM in the forecast.[379] The Company collected monthly historical data on actual DSM achievements, added the historical achievements to historical actual monthly sales to derive a time series of data excluding any DSM impacts, and used the restated time series as the input data to the regression model. We then reduced the forecast of sales excluding DSM by the amount of future DSM related to both historical achievements with continued impacts and planned future new programs.[380]

In comparison, by not making an adjustment for DSM impacts in the test year, the Department's forecast substantially overstates sales. This is particularly clear in the Department's forecast sales to the Large C&I class for 2014, an unreasonable result largely attributable to not making an adjustment for DSM.[381]

a. DSM impacts are not flat

The Department states that DSM savings and spending are not increasing and therefore no adjustment is necessary.[382] The Department fails to address how DSM

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[377] Ex. 38 Marks Direct at 33-34 and Figure 8.

[378] Ex. 38 Marks Direct, page 8 Figure 1.

[379] Ex. 38 Marks Direct at 33.

[380] Ex. 38 Marks Direct at 33.

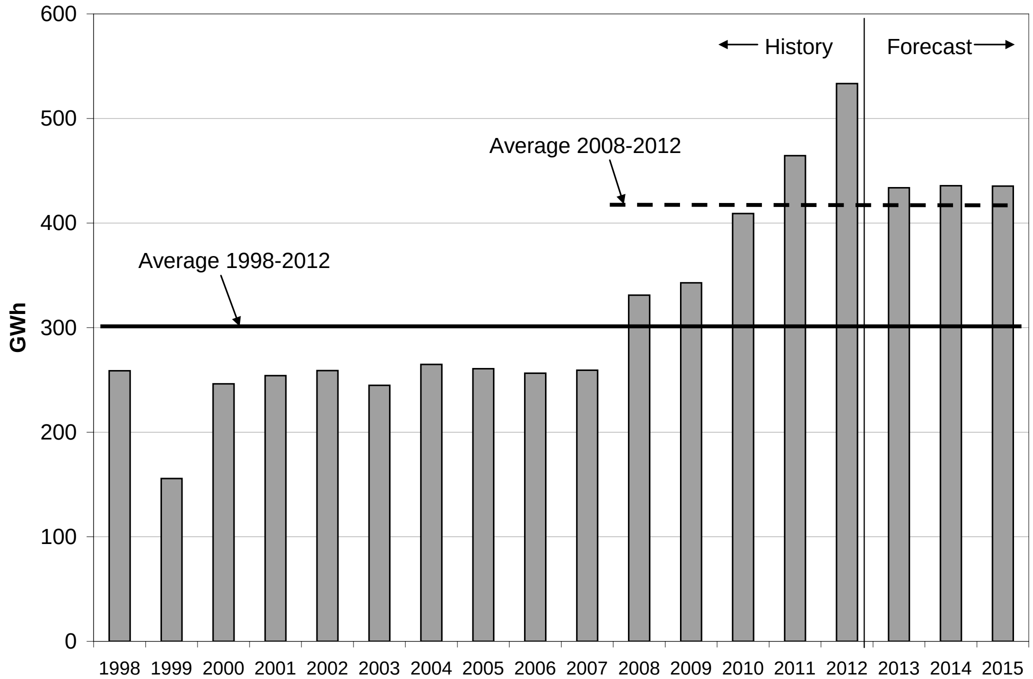
[381] Ex. 40 Marks Rebuttal at 20.

[382] Department Initial Brief At 174.

savings are reflected in the model and the difference between historical DSM, existing DSM and future DSM affecting sales in the test year.

In her Direct Testimony, Ms. Marks demonstrates the difference between actual, historical DSM embedded in the forecast and forecast DSM impacting the test year.[383]

Actual and Forecasted DSM Savings (First-Year Savings)



Further, as Company witness Ms. Sundin described, the effects of historical DSM, existing DSM and future DSM are accounted for in the model.[384] The DSM adjustment adjusts historical sales in order to generate a forecast that removes the impact of all past DSM achievements, allowing the company to project future sales independent of DSM.[385] The continuing impacts of existing DSM (actual achievements with remaining life in the test year after subtracting the life included in

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[383] Ex. 38 Marks Direct at 32.
[384] Ex. 42 Sundin Rebuttal at 9.
[385] Ex. 42 Sundin Rebuttal at 10.

historical DSM) are included, as well as new DSM achievements occurring in the forecast period.[386] New DSM is primarily offsetting the effect of expiring measures from prior CIP program years. It is appropriate to include the full DSM achievements as to disqualify part or all of the adjustment would cause the sales forecast to increase artificially.[387]

b. DSM savings are verified

The Department additionally raised concerns that the DSM savings are estimates.[388] However, the Department fails to address the extensive testimony of Company witness Ms. Sundin demonstrating that these savings are subject to rigorous review.[389] The energy savings and equipment lifetimes are calculated by the Company's engineering team applying standard industry practices and these calculations are reviewed by the Department itself.[390]

The forecast savings for these measures are built based on project and customer type for baseline and efficient equipment options, and the engineering analysis applied is built off of external industry resources and, if available, historical program results.[391] These savings calculations are thereafter subject to a rigorous measurement and verification process.[392] We thereafter apply the savings calculations approved by the Department.[393]

Although the Department raised concerns about the change to data in 1998, the Department failed to address that this change did not impact the DSM adjustment

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386 Ex. 42 Sundin Rebuttal at 11.
387 Ex. 42 Sundin Rebuttal at 11.
388 Department Brief at 170.
389 Ex. 42 Sundin Rebuttal at 12.
390 Ex. 42 Sundin Rebuttal at 12.
391 Ex. 42 Sundin Rebuttal at 12.
392 Ex. 42 Sundin Rebuttal at 13.
393 Ex. 42 Sundin Rebuttal at 12-13.

in the 2014 and 2015 sales forecasts.[394] A difference in the granularity of detail and how data was reported prior to 2000 resulted in the one-time variation and does not impact the forecast in this case.

c. Impacts on forecast for small C&I

Finally, the Department inaccurately attributes the difference between the forecast for July – December 2013 and actual results for the small commercial and industrial class to DSM.[395] The Department did not address the clear evidence in the record of the difference between billed sales and billed sales without the impacts of DSM.[396] And, as explained by Ms. Marks, the difference between the initial forecast for the last 6 months of 2013 and actual results is not attributable to accounting for DSM savings.[397] Mr. Shah did not describe any analysis to control for other factors that influenced the change. Without the DSM adjustment, sales would have been overforecast for the last half of 2013 for all classes.[398] The key driver of the underforecasting in the small C&I class was the underforecasting of households and total employment, not DSM.[399]

4. Price Variable

The Department raised concerns with the use of the price variable but recognized that to exclude the price variable would produce an unreasonable result. The Company concurs that the use of the variable improves the overall results and is

[394] Ex. 42 Sundin Rebuttal at 14.
[395] Department Initial Brief At 172.
[396] Ex. 38 Marks Direct at 34.
[397] Ex. 40 Marks Rebuttal at 13.
[398] Ex. 40 Marks Rebuttal at 13-14 and Table 4.
[399] Ex. 40 Marks Rebuttal at 6-7, 13.

appropriate for inclusion.[400] The Company agreed to work with the Department to see if improvements may be made.[401]

5. Customer Counts

The Company continues to support its customer count in this case. As Ms. Marks testified, the key driver for the change was updated economic data.[402] It is standard practice for both the household information and the employment information to be revised annually as new estimates are released.[403] Further, while the updated data resulted in some changes, the Company's 2013 forecast overall was very close to actuals in total.[404] In addition, the Company's updated forecast is based on the most up-to-date information available at the time rebuttal testimony was filed. It is appropriate to include this updated data in the sales forecast model in this case.

As reflected in the Department's testimony and brief, the use of actual results resolves the dispute regarding customer counts.

6. Large C&I Class

The Large C&I class has seen continued declines for the last several years. Contrary to the clear evidence that these sales are declining, the Department's forecast for this class was 3.3 percent higher than the Company's initial forecast, 3.9 percent higher than the Company's updated forecast and 3.8 percent higher than actual sales to this class in 2013.[405] This forecast is directly contrary to actual experience. Actual sales to the Large C&I class were 33,430 MWh *lower* than the Company's initial forecast and continued declines are expected.[406] The Department's forecast would

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[400] Ex. 40 Marks Rebuttal at 17.
[401] Ex. 40 Marks Rebuttal at 17.
[402] Ex. 40 Marks Rebuttal at 6-7.
[403] Ex. 40 Marks Rebuttal at 8.
[404] Ex. 40 Marks Rebuttal at 7.
[405] Ex. 40 Marks Rebuttal at 5 and 20.
[406] Ex. 40 Marks Rebuttal at 5.

result in a base revenue adjustment of $11.6 million when the clear evidence supports that sales to these customers has declined.[407]

7. Conclusion

The Company, the Department, and MCC agree that the use of weather-normalized 2014 sales is the preferred solution in the case. If the Commission declines to adopt the proposal, the Commission should adopt the Company's forecast as supported by the evidence in the record and accurately forecasting test year sales taking into account updated economic data, the impact of energy efficiency efforts, and the continued decline in sales for our large C&I customers.

B. Property Tax

The Company wants the 2014 test year property tax expense to be accurate. The resolution reached between the Company and the Department to base the 2014 property tax expense on the Department's alternative recommendation, subject to a true-up for actual accruals and further subject to a cap of $145 million for the Minnesota electric jurisdiction achieves this goal and should be adopted.[408] Even if the Commission does not accept the resolution, the Company remains willing to incorporate all actual information known about 2014 property taxes into the test year expense. If, however, the test year expense is not adjusted to reflect all actual information known about 2014 property taxes, then the Company's Direct Testimony forecast should be adopted.

The Company's forecasted 2014 test year property tax expense is $150 million on a Minnesota electric jurisdiction basis, which is based on total Company expense of $206 million.[409] More information is known regarding the Company's 2014

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[407] Ex. 40 Marks Rebuttal at 20.

[408] Ex. 117, Duevel Opening Statement at 1; Ex. 140; Heuer Opening Statement at 2; Ex. 451, Lusti Opening Statement at 2; Ex. 442, Lusti Surrebuttal at 30; Department Initial Brief at 134-135.

[409] Ex. 32, Duevel Direct at 1-2.

property tax levels than has been available in the past (due to the extended timeline of this case), which has allowed the Company to validate its forecast using actual 2014 data.[410] Based on that information, the Company expects the 2014 total Company property tax expense to be $200 million, or $145 million on a Minnesota electric jurisdiction basis.[411] The Company has consistently indicated it is willing to incorporate all actual information related to its 2014 property taxes into the determination of the 2014 test year revenue requirement.[412]

The Department has presented three different forecasts of 2014 test year property taxes.[413] If the resolution between the Company and the Department is not accepted, none of these forecasts should be adopted in place of the Company's $150 million forecast or the $145 million estimate based on actual 2014 information.

The Department's first forecast reduced 2014 property taxes by $13.5 million based on a thirteen-year look back (2001 – 2013).[414] The first forecast did not reflect the information that will drive the Company's actual 2014 property taxes.[415] The first forecast also did not account for important changes that occurred in the property tax system during the interim period.[416] The Department acknowledged its first forecast was outdated.[417] Such clearly outdated information should not be used to determine the 2014 property tax expense level.

The Department's second forecast was based on the average increase in property taxes from 2010-2013 and resulted in a $14 million decrease in 2014 property

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[410] Ex. 32, Duevel Direct at 7-9; Ex. 34, Duevel Rebuttal at 2-3.
[411] Ex. 34, Duevel Rebuttal at 3.
[412] Ex. 32, Duevel Direct at 8-9; Ex. 34, Duevel Rebuttal at 6.
[413] Ex. 437, Lusti Direct at 36; Ex. 442, Lusti Surrebuttal at 29-30.
[414] Ex. 437, Lusti Direct at 36.
[415] Ex. 34, Duevel Rebuttal at 7-9.
[416] Ex. 34, Duevel Rebuttal at 7-9.
[417] Ex. 442, Lusti Surrebuttal at 25-26.

taxes.[418] Again, this forecast is not based on any information that will be used to calculate the Company's actual 2014 property taxes: it reflects neither the level of investment nor the Department of Revenue's decisions related to the Company's 2014 property valuation. There is also enough actual 2014 information at this point to know the Department's second forecast is neither reasonable nor accurate. A recommendation that is clearly inaccurate should not be adopted.

The Department's third forecast incorporates the actual information related to the Company's 2014 property taxes, but makes a further adjustment based on the difference between the Company's June 2013 forecast of 2013 property taxes and the actual 2013 expense.[419] This results in a $9 million decrease in 2014 property taxes.[420]

The Company's June 2013 forecast included an adjustment to account for an expected increase in 2013 tax rates.[421] The Company did not include a similar, current-year adjustment for 2014 tax rates in its 2014 forecast.[422] The Department's forecast therefore results in an inappropriate doubling of the adjustment: once when the Company did not include a current year adjustment its Direct Testimony forecast and again as part of the Department's forecast. Further, when the adjustment for tax rates is removed from the June 2013 forecast (thereby putting the 2013 and 2014 forecasts on comparable basses), the Company's forecast is within 0.5% of the actual expense,[423] meaning no adjustment is necessary. The Department's third forecast

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418 Ex. 442, Lusti Surrebuttal at 29.

419 Ex. 442, Lusti Surrebuttal at 30.

420 Ex. 442, Lusti Surrebuttal at 30.

421 Ex. 32, Duevel Direct at Schedule 11. The adjustment was referred to in both Ex. 32, Duevel Direct Schedule 11 and in the Company's last rate case (Docket No. E002/GR-12-961) as the "4th Quarter Adjustment."

422 Ex. 32, Duevel Direct at 14.

423 Ex. 32, Duevel Direct at Schedule 11; Ex. 442, Lusti Surrebuttal at DVL-S-47. The Company's June 2013 forecast of the 2013 property tax expense $171.7 million (total Company). Subtracting the 4th Quarter adjustment reduces the forecast to $167.1 million (total Company), which is within 0.5% of the actual 2013 expense of $166.3 million identified on line 7 of Mr. Lusti's Surrebuttal Scheduled DVL-S-47.

reflects a double-counting of the same factor and should not be adopted if the resolution is not accepted.

VI. COMPLIANCE WITH PRIOR ORDERS

In its Initial Brief, the Department addresses the Company's compliance with the Commission's ordering paragraphs from the Company's most recent rate case regarding the Company's Annual Incentive Program (AIP), Sherco 3, and 2015 Step Compliance.[424] While the Department does not take a position on these compliance matters, they do recount the state of the record with respect to the Department's testimony on these issues. To help ensure a thorough review of these issues by the ALJ and the Commission, the Company provides some additional context and information on compliance matters.

Schedule 3 of the Direct Testimony of Company Witness Mr. David Sparby[425] provides each of the applicable compliance obligations of the Company – either statutory, rule based or otherwise ordered by the Commission – and where in the record the required information can be found. At almost sixty pages, this schedule demonstrates the thorough compliance process the Company has implemented. With the exception of the OAG's position regarding corporate aviation costs (which is discussed in detail in Section IV of this Reply Brief), no Party has directly challenged the Company's compliance with our compliance requirements.

1. AIP Compliance

No Party has challenged the reasonableness of the Company's AIP costs. However, in its discussion about whether the Company demonstrated that its KPI goals are hard to meet, the Department appears to be casting some doubt on the reasonableness of the structure of the Company's AIP program.

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[424]Department Initial Brief at pp. 253-263.
[425]Ex. 25, Sparby Direct.

At the outset, we note the record supports the reasonableness of the Company's AIP program. The Company's Annual Incentive Program is consistent with the Commission's order in 1992 and its last rate case and the Company has demonstrated that its AIP targets are reasonable in this rate case. After detailed discussion, the Company noted:

> The Company has evaluated its AIP targets to determine whether they are too easy to meet. Based upon the process for setting AIP goals and the fact that employees have not been able to achieve their AIP goals on some occasions, the Company concludes that our AIP goals strike the right balance between being difficult enough to challenge our employees, while not being so difficult as to serve as a disincentive.[426]

The Department concurs: "Mr. Lusti stated that it is reasonable to allow Xcel to recover its AIP compensation up to the 15 percent cap that it has proposed."[427]

The record also confirms that the Company demonstrated that the KPIs for its AIP program are hard to meet. The Department's review of our AIP goals bears this out. The Department's Initial Brief notes that in no year for which information was provided did all of the Company's business units meet their KPI goals to earn their AIP.[428] We recognize that our employees earned AIP in those years, but this is consistent with the structure of the plan, which has been found reasonable in the past:

> The intent of a performance goal is to motivate employees to provide excellent service to the Company and its customers. In order to serve as a motivation, however, the KPIs must be set at levels that can be met with the requisite amount of talent and effort. Goals that are not truly attainable actually serve as a disincentive, because

[426]Ex. 78, Figoli Direct at p. 42.

[427]Department Initial Brief at p. 255.

[428]Department Initial Brief at pp. 254-255.

> employees know they will not be rewarded for the extra effort they give.[429]
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> ***
>
> No [AIP is not a "bonus"]. If the goals are achieved … the employee's compensation level for that year is just then meeting market levels. Anything less than 100 percent of the full AIP amount puts the employee at a compensation level below what other companies and utilities are paying.[430]
>
> ***
>
> Several of our witnesses … discuss their aggressive scorecard goals and the difficulty meeting them … While our witnesses certainly have many stories of success in meeting their goals, these stories are meant to illustrate that these targets are, in fact, challenging and difficult to meet.[431]

Therefore, the ALJ and the Commission should find that the Company's Annual Incentive Program is reasonable and that the Company complied with Order Point 30 from the Company's last electric rate case.

2. Sherco 3

The Department determined that the Company has met its compliance obligations with respect to the November 2011 event at Sherco 3.[432] However, the Department noted two issues remain to be resolved: insurance recovery and insurance coverage.[433]

With respect to insurance recovery, the Company submitted the Direct Testimony of Mr. Ronald Brevig, which provided the then-best estimates of the

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[429] Ex. 78, Figoli Direct at pp. 42- 43.
[430] Ex. 78, Figoli Direct at p. 43.
[431] Ex. 78, Figoli Direct at p. 43.
[432] Department Initial Brief at pp. 256-257.
[433] *See* Department Initial Brief at pp. 257-261.

amounts of insurance recovery that the Company expected to receive.[434] However, at that time the Company had not yet reached a final resolution of insurance recovery issues with its insurers. Consequently, the Company has been providing quarterly updates as it works to a final resolution with its insurers for recovery of costs of the Restoration. These filings have demonstrated that the Company's insurance providers will cover the vast majority of the Sherco 3 Restoration costs[435] and that the Company's initial estimate of insurance recovery and its request for recovery in this rate case are within a range of reasonableness (approximately fifteen percent) of its most current estimates of total insurance recovery. The Company concurs with the Department that Mr. Lusti reserved the right to propose an adjustment to the Company's request based on the Company's June 30, 2014 Insurance Recovery Update.[436] However, the Company notes that neither Mr. Lusti nor any other Party has proposed an adjustment.

With respect to the prudence of the Company's insurance coverage, the Company also submitted the Direct Testimony of Mr. Michael Anderson to, among other things, discuss the terms of coverage applicable to the Sherco 3 Restoration Efforts, including issues related to replacement fuel coverage.[437] Company Witness Mr. Brevig noted that issues related to replacement fuel were being addressed in the relevant AAA proceedings.[438] Mr. Lusti concurred with the observation.[439] Both the Company and the Department agree that issues related to replacement fuel costs are most appropriately determined in the applicable AAA proceedings and there is therefore no issue for the ALJ or the Commission to address in this proceeding.

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[434] Ex. 56, Brevig Direct at pp. 47-59.
[435] Ex. 56, Brevig Direct at pp. 47-59.
[436] Department Initial Brief at p. 260.
[437] Ex. 35, Anderson Direct at pp. 24-31.
[438] Ex. 56, Brevig Direct at p. 47.
[439] Ex. 437, Lusti Direct at p. 68.

3. 2015 Step Compliance

The Company and the Department have resolved the most appropriate way to approach compliance obligations for the 2015 Step. Based on the facts and discussion provided by the Parties, the ALJ and the Commission should accept this outcome as a reasonable resolution of this novel issue.

VII. RATE DESIGN AND CCOSS

Except as discussed below, the Company relies on its Initial Brief to reply to the rate design and Class Cost of Service Study (CCOSS) issues addressed in parties' Initial Briefs.

A. Class Cost of Service Study

1. Other Production O&M

The Company primarily relies on its Initial Brief and the Initial Brief of the MCC to reply to the Department and OAG regarding the merits of using the predominant nature method to classify Other Production O&M costs.[440] Two items discussed in the Initial Briefs of the OAG and Department, however, require additional response.

The OAG claims the Commission has approved the use of the location method in the Company's last three rate cases.[441] This is not correct. In past cases, the Company classified and allocated all Other Production O&M plant using the overall investment method.[442] Under the overall investment method, total Other Production O&M costs were separated into capacity-related and energy-related components based on the overall percentage of capacity-related and energy-related

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[440] Company Initial Brief at 125-129; MCC Initial Brief at 17-18; Department Initial Brief at 272-274; OAG Initial Brief at 58-62.

[441] OAG Initial Brief at 59-62.

[442] Ex. 103, Peppin Rebuttal at 24.

fixed production plant.[443] The overall investment method is not consistent with the NARUC Manual, which calls for Other Production O&M costs to be separated into two buckets: costs that vary directly with the amount of energy produced and costs that do not vary directly with the amount of energy produced.[444]

In the 2012 rate case (Docket No. E002/GR-12-961), the Commission ordered the Company to bring its classification of Other Production O&M into alignment with the process described in the NARUC manual. Specifically, the Commission required the Company to engage in a two-step process:

> In the initial filing of its next rate case, Xcel shall refine its Class Cost of Service Study cost allocation method <u>by identifying any and all Other Production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators</u>, <u>while allocating the remainder of Other Production O&M costs on the basis of the Production Plant</u>.[445]

To comply with the first step of process (indicated with the single underline above), the Company examined each of the 117 cost items that make up Other Production O&M.[446] Based on that analysis, the Company identified chemicals and water use as being energy-related.[447] Parties appear to agree with this classification.[448]

The controversy in this case is over the second step of the process (indicated with the double underline above). The Department and OAG recommend performing the

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[443] Ex. 103, Peppin Rebuttal at 24.

[444] Ex. 103, Peppin Rebuttal at 24 (discussing the classification methodology described on pages 64-66 of the National Association of Utility Commissioners, <u>Electric Utility Cost Allocation Manual</u> (Jan. 1992)).

[445] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at Order Point 49 (Sept. 3, 2013) (emphasis added) [*hereinafter* E002/GR-12-961 ORDER].

[446] Ex. 102, Peppin Direct at 19 and Schedule 7.

[447] Ex. 102, Peppin Direct at 19-20.

[448] Company Initial Brief at 127 (citing Ex. 408, Ouanes Direct at 35; Ex. 377, Nelson Rebuttal at 18; Ex. 343, Maini Direct at 25; Ex. 262, Pollock Rebuttal at 16-23; Tr. Vol. 4 at 100-101 (Ouanes)).

second step using the location method.[449] The OAG partially relies on its assertion that moving away from the location method would undue past precedent: as explained above, the OAG's position is mistaken.[450]

The OAG and Department also claim the Company previously opposed, and the Commission previously rejected, the predominant nature method.[451] Both are incorrect. The method supported by the XLI in past cases is described in the NARUC Manual as follows:

> One common method for handling [accounts that contain both demand-related and energy-related components] is to separate the labor expense from the materials expense: labor costs are then considered fixed and therefore demand-related, and materials costs are considered variable and thus energy-related.[452]

This is different from the predominant nature method, which is described as: "[a]nother common method is to classify each account according to its 'predominant' – i.e., demand-related or energy-related – character."[453] The predominant nature method is a more refined analysis than what was proposed by XLI in past cases because it is supported by an examination of each of the 117 different Other Production O&M accounts. Given the presence of a new, detailed analysis that was

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[449] Department Initial Brief at 274; OAG Initial Brief at 62.

[450] OAG Initial Brief at 62 ("The company has not provided any basis to reverse three rate cases precedents in which the location method was used….").

[451] Department Initial Brief at 273; OAG Initial Brief at 59-60.

[452] Ex. 103, Peppin Rebuttal at 26 (quoting the National Association of Utility Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992). *See also* E002/GR-10-971 ORDER at 17 ("XLI disputed Xcel's classification of "other" production operation and management costs as 15% demand-related and 85% energy-related. XLI suggests that these costs should be divided into labor-related and materials-and-maintenance-related costs, and that if they were re-classified in that manner, the proper attribution of those costs would be 35% demand-related and 65% energy-related. XLI argues that its preferred division of these costs is appropriate because labor costs are fixed and relate to operating a plant independently of the amount of energy produced by the plant, and therefore relate to demand, while materials and maintenance, as variable costs, relate to energy production and should be attributed to energy.").

[453] Ex. 103, Peppin Rebuttal at 26 (quoting the National Association of Utility Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992).

not performed in past cases, the Company's preference for the predominant nature method is reasonable.

The Company, MCC and XLI have all discussed at length the benefits of the predominant nature method.[454] The method is supported by a new analysis that was not performed in prior cases. It does not rely on proxies, but rather focuses on the true nature of the costs being examined. Ultimately, the predominant nature method leads to a better measurement of the cost of service and should be adopted.

2. Customer-Related Distribution Costs

The Company primarily relies on its Initial Brief to reply to the OAG regarding the classification Customer-Related Distribution Costs,[455] but several aspects of the OAG's Initial Brief merit additional response.

In its Initial Brief, the OAG continues to assert that the zero-intercept method is superior to the Minimum Distribution System (MDS) method.[456] The Company explained in its Initial Brief that the OAG's position is not supported in the record, is inconsistent with industry practice, and is contrary to Commission precedent.[457] The OAG acknowledges that it has no zero-intercept study to support its position, but attempts to construct a "proxy" for the zero-intercept method in its Initial Brief.[458] According to the OAG, "removing the materials costs from Xcel's minimum system study provides a proxy for estimating the results of a zero-intercept analysis."[459] The OAG's proxy is fundamentally flawed and should be ignored. The NARUC Manual clearly states that a zero-intercept study is to be performed on an installed cost

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[454] Company Initial Brief at 126-129; MCC Initial Brief at 17-18; Ex. 102, Peppin Direct at 19-25; Ex. 103, Peppin Rebuttal at 23-28; Ex. 104, Peppin Surrebuttal at 6-9; Ex. 343, Maini Direct at 24-26; Ex. 345, Maini Surrebuttal at 17-18; Ex. 262, Pollock Rebuttal at 16-21.

[455] Company Initial Brief at 1229-131; OAG Initial Brief at 45-55.

[456] OAG Initial Brief at 48-50.

[457] Company Initial Brief at 129-131.

[458] OAG Initial Brief at 50. *See also* Tr. Vol 3 at 228-229, 243-244 (Nelson).

[459] OAG Initial Brief at 50.

basis,[460] which *includes* materials costs.[461] Furthermore, the Company's study already includes an adjustment that accounts for the demand associated with the minimum sized system,[462] making an adjustment for the "materials used…to serve a specific level of demand" unnecessary.[463]

The OAG also continues to selectively rely on current installation standards in assessing the Company's minimum system study. For example, the OAG asserts the Company's minimum system study is flawed because it does not reflect the current minimum sized single-phase primary underground conductor.[464] At the same time, the OAG claims that it would be inappropriate to reflect the Company's current minimum sized poles.[465] The OAG's selective focus on some, but not all, of the Company's current minimum installation standards leads to an arbitrary adjustment – a fact acknowledged by the OAG.[466] Such arbitrary adjustments are improper and should be rejected.[467]

The OAG questions the relevance of the Company's current minimum sized pole by stating the Company "has not identified the specific cost difference between

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460 Ex. 143, Excerpts from the National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual at 11 (page 92 of the manual)("The technique is to related ***installed cost*** to current carrying capacity or demand rating, create a curve for various sized of the equipment involved, using regression techniques, and extend the curve to a no-load intercept.").

461 Ex. 104, Peppin Surrebuttal at 5.

462 Company Initial Brief at 130; Ex. 102, Peppin Direct at Schedule 2, Appendix 2, page 3; Tr. Vol. 3 at 247-248(Nelson).

463 OAG Initial Brief at 50.

464 OAG Initial Brief at 51.

465 OAG Initial Brief at 52. The OAG ignores the fact that reflecting current minimum sized transformers would also increase customer-related costs. *See* Ex. 70, Foss Rebuttal at 7 (stating the cost of the current minimum sized transformer exceeds the cost of the transformer used in the minimum system study).

466 Ex. 375, Nelson Direct at 26; Tr. Vol. 3 at 249-250 (Nelson).

467 E002/GR-85-558 ORDER at 28-29 ("The ALJ rejected the three modifications [to the Company's CCOSS] suggested by the RUD-AG. He rejected the minimum system adjustment because there is no indication in the record that the RUD-AG's proposed solution does anything but produce an arbitrary number for the amount of customer costs…. The Commission agrees in every respect with the findings of the ALJ regarding the class cost of service study and adopts his findings and supporting discussion as its own.").

the 30-foot pole used in its minimum system study and the 35-foot poles that it currently installs."[468] This is not correct.

The Company provided materials cost comparisons for both poles and single-phase primary underground conductor in its responses to OAG Information Requests No. 753 and 754 (OAG-753 and OAG-754). The cost comparisons were marked as Trade Secret in the responses. Mr. Nelson's Surrebuttal schedules include public and Trade Secret versions of OAG-754 (cable), but only included the public version of OAG-753 (poles).[469] Mr. Nelson used the cable cost information from OAG-754 to support the analysis contained in his Surrebuttal Testimony and the OAG used the cable cost information extensively in its Initial Brief.[470] The OAG chose not to perform similar analyses for cable.

To clear the record, the Company provides the following cost information related to poles, based on the trade secret version of OAG-753:

- The materials cost of 35-foot poles is greater than the materials costs of 30-foot poles; and
- The materials cost of the Company's current minimum sized pole is greater than the installed cost (materials, plus labor and overheads) of the minimum sized pole used in the minimum system study.

This last point is important, as it shows that any move to update the minimum system study to reflect the Company's current minimum sized pole would increase customer-related costs.

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[468] OAG Initial Brief at 52.

[469] The Trade Secret version of OAG-754 was included in Ex. 381, Nelson Surrebuttal Trade Secret Schedules as REN-31; the public version was included in Ex. 379, Nelson Surrebuttal Public Schedules as REN-31. The public version of OAG-753 was included in both Ex. 381, Nelson Surrebuttal Trade Secret Schedules and Ex. 379, Nelson Surrebuttal Public Schedules as REN-32.

[470] Ex. 378, Nelson Surrebuttal at 7; Ex. 380, Nelson Trade Secret Surrebuttal at 7; OAG Initial Brief at 50-51.

Finally, contrary to statements in the OAG's Initial Brief,[471] the Company has explained the minimum sized equipment used in the minimum system study was selected according to the Company's then-current minimum installation standards.[472] The Company has also explained that its calculation of the per unit installed cost of the equipment used in the minimum system study is consistent with the method approved by the Commission in the Company's past rate cases.[473] Both elements are appropriate for use in this case.

The Company has committed to refreshing its minimum system study prior to filing its next rate case.[474] The refresh will reexamine all of the assumptions of the minimum system study, including the engineering assumptions supporting the minimum sized system and the installed cost of the minimum sized system. As part of the refresh, the Company will also evaluate whether it can gather sufficient data to perform a zero-intercept analysis and, if it is able to do so, will include a zero-intercept analysis in the initial filing of the Company's next rate case.[475] For this case, however, the Company continues to support its calculation of the customer-related portion of distribution costs as being reasonable and sufficient for ratemaking purposes.

3. Other CCOSS Items

The Company relies on its Initial Brief and the Initial Briefs other parties to address the following issues:

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[471] OAG Initial Brief at 53-54.
[472] Ex. 70, Foss Rebuttal at 2-4.
[473] Ex. 103, Peppin Rebuttal at 33; Ex. 104, Peppin Surrebuttal at 5-6.
[474] Company Initial Brief at 131.
[475] Ex. 103, Peppin Rebuttal at 31, 34-35; Ex. 104, Peppin Surrebuttal at 5-6.

- Classification of Fixed Production Plant: The Company's Initial Brief and the Initial Brief of the Department in reply to the MCC and XLI;[476]
- Company-Owned Wind: The Company's Initial Brief and the Initial Brief of the MCC in reply to the Department and OAG;[477]
- Calculation of D10S Capacity Allocator: The Company's Initial Brief and the Initial Brief of the MCC in reply to the OAG;[478] and
- Allocation of Economic Development Discounts: The Company's Initial Brief and the Initial Brief of the MCC in reply to the Department and OAG.[479]

B. Revenue Allocation

The Company relies on its Initial Brief to reply to parties regarding the Allocation of Revenue in this case.[480]

C. Rate Design Proposals

Multiple statutory provisions are relevant to the Company's rate design.[481] The Commission must weigh and balance these sometimes competing directives, a task

[476] Company Initial Brief at 131-133; Department Initial Brief at 272, 276-277; MCC Initial Brief at 14-16; XLI Initial Brief at 13-16.
[477] Company Initial Brief at 125-129; MCC Initial Brief at 18-21; Department Initial Brief at 267-272; OAG Initial Brief at 55-58.
[478] Company Initial Brief at 135-136; MCC Initial Brief at 16-17; OAG Initial Brief at 63-65.
[479] Company Initial Brief at 136-137; MCC Initial Brief at 16-17; Department Initial Brief at 274-275; OAG Initial Brief at 62-63.
[480] Company Initial Brief at 138-140; Department Initial Brief at 283-288; OAG Initial Brief at 65-66; MCC Initial Brief at 22-23; XLI Initial Brief at 16-17; AARP Initial Brief at 18-19; Commercial Group Initial Brief at 11; SRA Initial Brief at 12.
[481] *See e.g.*, Minn. Stat. §§ 216B.01; 216B.03; 2016B.16, subd. 6; 216B.16, subd. 15; 216B.2401.

that falls within the Commission's quasi-legislative authority.[482] This balancing appropriately incorporates all relevant provisions.[483] Arguments that seize on certain legislative directives while ignoring others are contrary to Minnesota law.[484] The Company's rate design proposals strike an appropriate balance against all relevant statutory considerations and should be approved.

1. Customer Charge

The Company primarily relies upon its Initial Brief to reply to parties regarding the Company's proposed customer charges.[485] The Company also relies on the portions of the Department's Initial Brief that explain why some increase in the customer charge is reasonable and the portions that identify the flaws associated with the positions of the OAG and ECC on this topic.[486]

CEI asserts the customer charge is currently higher than the fixed cost of providing service.[487] CEI is incorrect. The fixed cost of providing service to Residential customers is $15.70; the fixed cost of providing service to Small General Service customers is $16.65.[488] The lower value calculated by CEI inappropriately

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482 *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977).

483 Minn. Stat. § 645.17 (2); *Harris v. County of Hennepin*, 679 N.W.2d 728, 732 (Minn. 2004)("Statutes should be read as a whole with other statutes that address the same subject."); *Kollodge v. F. & L. Appliances, Inc.*, 248 Minn. 357, 360–61 (Minn. 1956)("It is a cardinal rule of statutory construction that a particular provision of a statute cannot be read out of context but must be taken together with other related provisions to determine its meaning. 'Parts of a statute are not to be viewed in isolation. A statute should be construed as a whole. Words and sentences are to be understood in no abstract sense, but in the light of their context, which communicates meaning and color to every part.'").

484 *See e.g.,* ECC Initial Brief at 2, 19; CEI Initial Brief at 1-3.

485 Company Initial Brief at 140-143; Department Initial Brief at 289-294; OAG Initial Brief at 75-78; CEI Initial Brief at 6-16; ECC Initial Brief at 19-23; AARP Initial Brief at 19-23.

486 Department Initial Brief at 289-294, 298-304.

487 CEI Initial Brief at 9-12. The OAG also cites the CEI's calculation of customer-related costs in its Initial Brief. *See* OAG Initial Brief at 77.

488 Ex. 107, Huso Rebuttal at 29.

excludes customer-related costs and is contrary to industry guidance and Commission precedent[489] – it should be ignored.

CEI's claims regarding the use of the cost of service in evaluating the customer charge and the importance of intra-class equity are contrary to Commission practice.[490] For example, the Commission's June 9, 2014 Findings of Fact, Conclusions, and Order in Docket No. G008/GR-13-316, includes the following:

> The Commission concludes, however, that a modest increase in the residential customer charge remains appropriate. *Maintaining the customer charge at its current level would effectively increase intra-class subsidies for low-usage customers, so the principle of intra-class rate design equity supports some increase*.
>
> Having determined that the ALJ's recommended increase is larger than warranted, the Commission concludes that the Department-recommended residential customer charge amount of $9.50 best balances the many remaining concerns identified by all the parties. These concerns include, but are not limited to: *the principle of moving the fixed cost charge closer to the class's average fixed cost*; *promoting intra-class equity*; minimizing rate shock that certain customers may experience in response to a large, sudden change in the fixed monthly charge; and the Commission's mandate to set rates that to the maximum reasonable extent encourage energy conservation.[491]

Similar to its arguments regarding the calculation of the customer-related costs, CEI's positions regarding the role of cost and the importance of intra-class equity are contrary to Commission practice and should be disregarded.

Finally, a revenue decoupling mechanism is not an exact substitute for moving the customer charge closer to cost. The Commission has previously recognized that

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489 Ex. 103, Peppin Rebuttal at 36; Ex. 104, Peppin Surrebuttal at 2-4, Schedule 1.

490 CEI Initial Brief at 9-16.

491 *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 52 (June 9, 2014) (emphasis added) [*hereinafter* G008/GR-13-316 ORDER].

decoupling may fulfill "a revenue-stabilization objective that might otherwise be accomplished by an increased customer charge."[492] But the Commission also acknowledged that moving the customer charge closer to cost helps promote intra-class equity[493] – the same goal the Company is trying to achieve in this case.[494]

The Company's proposed customer charges are reasonable and should be adopted.

2. Interruptible Rates

The Company primarily relies upon its Initial Brief to reply to the Initial Briefs of the Department, MCC and XLI.[495]

The Company acknowledges that his has lost interruptible load since its last rate case.[496] Contrary to the assertion of the MCC, however, the Company has not determined that the decrease in interruptible load "is likely the result of the lack of credit."[497] Rather, the Company has explained that the level of interruptible credits may be <u>one of the factors</u> contributing to the decline.[498] Other factors contributing to customers' decisions to discontinue interruptible service include adjustments in environmental policy, changes in customer usage and variations in business need.[499] The Company's proposed interruptible rate discount levels strike an appropriate balance between the need to attract and maintain an optimal amount of interruptible service while providing value to the customer population as a whole. They should be adopted.

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[492] G008/GR-13-316 ORDER at 51.

[493] G008/GR-13-316 ORDER at 52.

[494] Ex. 105, Huso Direct at 16.

[495] Company Initial Brief at 143-145; Department Initial Brief at 297-298; MCC Initial Brief at 23-27; XLI Initial Brief at 18-19.

[496] Company Initial Brief at 144; Ex. 145, Mani Opening Statement at 1 and Attachment A (Company response to MCC-157); Tr. Vol 2 at 183 (Huso).

[497] MCC Initial Brief at 24.

[498] Tr. Vol 2 at 183 (Huso).

[499] Ex. 145, Mani Opening Statement at Attachment A (Company response to MCC-157).

XLI and MCC continue to assert the level of interruptible rate discounts should be set according to avoided cost.[500] The Company has explained in this case (and in the 2012 rate case) that avoided cost can be used as reference point in assessing the reasonableness of the interruptible rates,[501] but that it cannot be applied directly to an embedded cost rate.[502] The MCC and XLI positions are incorrect and should not be adopted.

3. IBR

The Company appreciates the concerns of the OAG regarding the scope of the Stipulation on Inclining Block Rates.[503] The Company raised questions about the prudence of implementing an inclining block rate (IBR) structure in this case and believes additional review is necessary.[504] The Company welcomes the OAG's participation in any subsequent review of a potential IBR structure. The Company is also willing to work with all interested parties and the Commission to make sure any review process is thorough and robust.[505]

D. Tariff Proposals

The Company relies upon its Initial Brief to reply to the Initial Brief of the MCC regarding tariff proposals.[506]

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[500] MCC Initial Brief at 25-27; XLI Initial Brief at 18-19.

[501] Ex. 107, Huso Rebuttal at 36. Also, Mr. Huso testified that he was not familiar enough with CIP assumptions to confirm that the CIP avoided costs discussed by the MCC were reasonable. He was able to confirm that he assumes the Company would use reasonable assumptions in its CIP analysis. Tr. Vol. 2 at 185; MCC Initial Brief at 25.

[502] Company Initial Brief at 144-145; Ex. 107, Huso Rebuttal at 36-37; E002/GR-12-961 ORDER at 13-14(rejecting MCC proposal to set interruptible rate discounts at avoided cost)

[503] Ex. 135, Stipulation on Inclining Block Rates.

[504] Ex. 107, Huso Rebuttal at 10-24; Ex. 108, Huso Surrebuttal at 2-6; Ex. 74, Gersack Surrebuttal at 2-5.

[505] OAG Initial Brief at 75.

[506] Company Initial Brief at 145-146; MCC Initial Brief at 27-29.

1. Definition of Peak Period for Time of Day Rates

XLI points to the cost differential associated with system seasonal capacity requirements as justifying its proposed change to the definition of peak period.[507] Seasonal capacity cost differentials are already reflected in the Company's demand charge.[508] Further, XLI has provided no evidence that the *hourly* differential captured in the current peak period definition is impacted by the *seasonal* differential cited by XLI. XLI's recommendation should not be adopted.

E. Decoupling

The Company relies on its Initial Brief and the Initial Brief of the Department and CEI to reply to the Initial Briefs of the OAG and AARP on the issue of decoupling policy.[509] The Company relies on its Initial Brief and, in some respects, the initial brief of CEI to reply to the Initial Briefs of the Department, OAG, ECC and AARP regarding the design of the proposed decoupling mechanism.[510]

The Department concludes the Company's proposed partial decoupling mechanism would have an adverse impact on customers.[511] To help "mitigate" the adverse impact associated with decoupling, the Department proposes to include the effects of weather within the decoupling mechanism.[512] There are three problems

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[507] XLI Initial Brief at 19-20.

[508] Company Initial Brief at 146;

[509] Company Initial Brief at 149-151; Department Initial Brief at 191-196; CEI Initial Brief at 16-31; OAG Initial Brief at 66-71; AARP Initial Brief at 4-13.

[510] Company Initial Brief at 149-151; CEI Initial Brief at 19-29; Department Initial Brief at 197-214; OAG Initial Brief at 69-71; AARP Initial Brief at 16-18; ECC Initial Brief at 23-25.

[511] Department Initial Brief at 197-206.

[512] Department Initial Brief at 197, 202, 204

> Instead of disapproving decoupling as unreasonable, the Commission could assess the risks of customers paying higher costs than under traditional rate design and <u>address whether the adverse ratepayer impacts could be mitigated by changing the type of decoupling choosing, or modifying the parameters of the utility's decoupling proposal</u>. The Department's analysis offered the Commission <u>mitigation tools in the form of</u> a cap on surcharges set at a reasonable amount of three percent, and suggested the program be only a pilot, and employ

with the Department's position. First, the "adverse impact" identified by the Department (which occurs under both full and partial decoupling)[513] is simply a measure of the difference between authorized and actual revenue per customer approved in the Company's past rate cases. It is unclear how payment of the revenue per customer adopted and approved by the Commission during a rate case can be equated to an adverse impact. Second, decoupling is intended to address "a utility's disincentive to promote energy efficiency."[514] It is not intended to be a weather-hedging mechanism. Third, there is no guaranty that weather and non-weather effects will offset one another.[515]

Given this is the first electric decoupling mechanism in this State, the Company's desire to take a gradual approach, and the fact the Company's proposed RDM fully addresses the disincentive to promote energy efficiency,[516] the Company's partial decoupling mechanism should be approved.

> full decoupling, which Mr. Davis's analysis showed could result in significantly lower surcharges than partial decoupling under multiple economic and weather conditions.
> …
> The most important information shown in the data Xcel provided is that partial decoupling surcharges would have resulted in much higher rates for residential customers than the full decoupling surcharges. Further, full decoupling could lead to lower rates than under traditional regulation.
> …
> The fact that partial decoupling would have resulted in a surcharge but full decoupling would have resulted in a refund during these years suggests that Xcel experienced non-normal weather (higher THI), which boosted its sales. Weather-related increased sales would be taken into account in a full decoupling calculation, but would not be taken into account in Xcel's proposed RDM.
> …
> The factor that distinguishes partial and full decoupling is only the weather; mild summer weather could lead to less electric energy use and higher rates under full decoupling but not under partial decoupling. (Emphasis added; internal citations omitted)

513 Department Initial Brief at 198-199 (indicating both full and partial decoupling could lead to surcharges).

514 Minn. Stat. § 216B.2412.

515 Ex. 110, Hansen Rebuttal at 8.

516 Ex. 109, Hansen Direct at 12; Ex. 417, Davis Direct at 18; Ex. 290, Cavanagh Direct at 7; Tr. Vol 4 at 141-142 (Davis).

Certain parties also identify a hard cap as being a tool that can mitigate adverse impacts associated with decoupling.[517] The Company and the CEI's explained, however, that a hard cap reintroduces a disincentive to promote energy efficiency.[518] The Department's reliance on the DSM financial incentive risks treating the two programs (decoupling and the DSM financial incentive) as substitutes, contrary to legislative guidance.[519] And the Department states it plans to recommend changes to the DSM financial incentive in the future,[520] which could significantly change the Department's analysis. The soft cap proposed by the Company is reasonable and should be adopted.

Finally, the record in this case fully explains: 1) how sales would be forecasted in the RDM;[521] 2) why the Company chose to pursue a partial decoupling mechanism;[522] 3) that decoupling has not and will not lead to customer confusion;[523] 4) that the Company's proposed method for calculating RDM surcharges and refunds is better for low-use customers;[524] and 5) that changes in sales to business customers would have no impact on the RDM adjustment for Residential customers.[525]
The Company's proposed RDM is reasonable and should be adopted.

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[517] Department Initial Brief at 206-214; OAG Initial Brief at 70-71; AAPR Initial Brief at 17.
[518] Company Initial Brief at 150; CEI Initial Brief at 20-21.
[519] Company Initial Brief at 147.
[520] Department Initial Brief at 209-210, 215.
[521] Ex. 109, Hansen Direct at 11, 14 (addressing concerns raised in Department Initial Brief at 187).
[522] Ex. 110, Hansen Rebuttal at 8-9; (addressing concerns raised in OAG Initial Brief at 69).
[523] Ex. 110, Hansen Rebuttal at 16-17; CEI Initial Brief at 28-29 (addressing concerns raised in OAG Initial Brief at 70).
[524] Ex. 111, Hansen Surrebuttal at 10; CEI Initial Brief at 27 (addressing concerns raised in ECC Initial Brief at 23-25).
[525] Ex. 110, Hansen Rebuttal at 21-22 (addressing concerns raised in AARP Initial Brief at 9).

VIII. CONCLUSION

Through the record in this case, the Company has demonstrated the reasonableness and prudence of its test year costs.

Respectfully submitted by:

/s/

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STATE OF MINNESOTA
BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota

OAH Docket No. 68-2500-31182
MPUC Docket No. E002/GR-13-868

XCEL ENERGY'S PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

October 14, 2014

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In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota	OAH Docket No. 68-2500-31182 MPUC Docket No. E002/GR-13-868

XCEL ENERGY'S PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

The above-entitled matter came for evidentiary hearing before Administrative Law Judge Jeanne M. Cochran on August 11-15, 2014 in St. Paul, Minnesota. Public hearings were held in Eden Prairie, Mankato, Minneapolis, St. Cloud, St. Paul, and Woodbury between June 23, 2014 and June 27, 2014. Public comments were received until July 7, 2014.

Post-hearing briefs were filed on September 23, 2014, and responsive briefs were filed on October 14, 2014. The hearing record closed upon receipt of the last post-hearing briefs on October 14, 2014.

The parties to this proceeding are: Northern States Power Company, doing business as Xcel Energy (Company or Xcel Energy or NSPM); the Minnesota Department of Commerce, Division of Energy Resources (Department); the Minnesota Office of Attorney General – Antitrust and Utilities Division (OAG); the Xcel Energy Large Industrials (XLI); the Minnesota Chamber of Commerce (MCC); the Commercial Group (Commercial Group); the Energy CENTS Coalition (ECC); the Suburban Rate Authority (SRA); the Industrial, Commercial and Institutional Customer Group (ICI); Minnesota Center for Environmental Advocacy, Izaak Walton League of America-Midwest Office, Fresh Energy, Sierra Club, and Natural

Resources Defense Council, collectively the Environmental Interveners (EIs); and the American Association of Retired Persons (AARP).

The Company sponsored prefiled written testimony of 34 witnesses and the intervenors collectively sponsored prefiled written testimony of 21 witnesses.

Appearances were made by the following: For Xcel Energy, Aakash Chandarana, Lead Regulatory Attorney - North, Xcel Energy, Kari L. Valley, Assistant General Counsel, Xcel Energy, James R. Denniston, Assistant General Counsel, Xcel Energy, Stephen E. Fogel, Assistant General Counsel, Xcel Energy, Richard J. Johnson and Patrick Zomer, Moss & Barnett, PA; for the Department, Julia E. Anderson, Linda S. Jensen, and Peter Madsen, Assistant Attorneys General; for the OAG, Ian Dobson and Ryan Barlow, Assistant Attorneys General; for the SRA, James Strommen, Attorney at Law, Kennedy & Graven; for MCC, Benjamin Gerber, Attorney at Law, Richard J. Savelkoul, Attorney at Law, Martin & Squires; for XLI, Andrew P. Moratzka and Sarah Johnson-Phillips, Attorneys at Law, Stoel Rives LLP; for the Commercial Group, Alan R. Jenkins, Attorney at Law, Jenkins at Law, LLC; for ECC, Pam Marshall, Executive Director, Energy CENTS Coalition; for ICI Group, Peder Larson and Connor T. McNeillis, Attorneys at Law, Larkin Hoffman; for the EIs, Kevin Reuther and Samantha Williams, Attorneys at Law; and for AARP, John B. Coffman, Attorney at Law.

STATEMENT OF THE ISSUES[1]

On November 4, 2013, the Company filed a petition to increase its electric rates in Minnesota. The Company sought authority to increase electric rates through a multi-year rate plan (MYRP) pursuant to Minn. Stat. § 216B.16, subds. 1 and 19 (MYRP Statute). The Company's MYRP is a two-year proposal, with the first year revenue requirement calculated from a traditional test year (2014) and the second year

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[1] A Master Exhibit List, including links to all exhibits received into evidence, was efiled by the court reporter on September 19, 2014 (eDockets Doc. No. 20149-103157-01).

(2015 Step) limited to specific capital additions and related costs.[2] The Company's MYRP requested a two-year increase that includes an increase of $192.7 million, or 6.9 percent, for 2014 (test year), and an additional increase of $98.5 million, or 3.5 percent, for 2015 (2015 Step) for a total increase of $291.2 million, or 10.4 percent.[3] The 2014 and 2015 revenue deficiencies are based on a 10.25 percent return on equity. The Company also requested an interim rate increase of $127.4 million, or 4.57 percent, on an annualized basis until the Commission decides final rates.[4]

On January 2, 2014, the Commission issued a Notice and Order for Hearing, referring the matter to the Office of Administrative Hearings for contested case proceedings. The Notice and Order for Hearing set forth the following issues to be addressed:

(1) Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings by the Company?
(2) Is the rate design proposed by the Company reasonable?
(3) Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?
(4) Has the Company fully complied with past Commission orders?
(5) How should the Commission incorporate into this case the results of the ongoing investigation into the prudence of Xcel's expenditures for life cycle management and the extended power uprate at the Monticello Nuclear Generating Plant?
(6) How should the proceeds of any insurance claims and litigation proceeds related to the Company's Sherburne County Generating Station Unit 3 be incorporated into Xcel Energy's rates?
(7) What will be the short- and long-term consequences of the rate mitigation strategy proposed by the Company?

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

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[2] Ex. 12, Filing Letter at 1.
[3] Ex. 12, Filing Letter at 1.
[4] Ex. 12, Filing Letter at 1.

FINDINGS OF FACT

I. INTRODUCTION AND OVERVIEW

A. Summary of the Application

1. The Company's Application to increase electric rates in Minnesota requested an increase of $192.7 million, or 6.9 percent, for 2014, and an additional increase of $98.5 million, or 3.5 percent, for 2015, for a combined total requested increase of $291.2 million, or 10.4 percent, effective January 3, 2014. The Application was based on a 2014 test year, a 2015 Step Year, and a Minnesota jurisdiction electric operations overall retail revenue requirement of $3.081 billion.[5]

2. The Company's Application also included two rate moderation proposals. The first relates to amortization of theoretical depreciation reserve surplus for the Company's transmission, distribution, and general assets. The second relates to the use of settlement payments from the Department of Energy (DOE).[6] The Company stated that these rate moderation proposals will enable more moderate and predictable year-to-year rate increases by offsetting the immediate impacts related to the Company's anticipated capital additions.[7]

3. In the course of this proceeding, many issues were resolved among the parties. The Company also updated its cost of service as new information became available.

4. In Rebuttal Testimony, the Company revised its requested increase to $169.5 million for 2014, and $95.1 million for 2015, for a combined total requested increase of $264.5 million.[8]

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[5] Ex. 88, Heuer Direct at 1.
[6] Ex. 99, Clark Direct at 26-30.
[7] Ex. 99, Clark Direct at 29.
[8] Ex. 90, Heuer Rebuttal at 1-2.

5. During the evidentiary hearing, the Company revised its requested increase to $142.2 million for 2014, and $106.0 million for 2015, for a combined total requested increase of $248.1 million.[9]

6. In its October 7, 2014 updated Final Issues List, the Company revised its requested increase to $142.2 million for 2014, and $106.9 million for 2015, for a combined total increase of $249.0 million.[10]

B. The Parties

7. Northern States Power Company, a Minnesota corporation, serves Minnesota customers and is a subsidiary of Xcel Energy Inc. (XEI), a public utility holding company with four utility subsidiaries that serve electric and natural gas customers in eight states.

8. The Minnesota Department of Commerce, Division of Energy Resources (Department) represents the interests of the State's ratepayers in rate proceedings. Department staff reviews the testimony and schedules filed by the Applicant and other parties to assure their accuracy and completeness. The Department filed testimony and arguments addressing the reasonableness of the elements of the rate.

9. The Office of Attorney General –Antitrust and Utilities Division (OAG) represents the interests of residential and small business ratepayers. Its staff reviews the testimony and schedules filed by the Applicant and other parties. The OAG filed testimony and arguments intended to protect those interests.

10. The Xcel Large Industrials (XLI) includes some of Xcel Energy's large retail electric customers. Their costs of production could be significantly affected by a rate increase.

11. The Minnesota Chamber of Commerce (MCC) represents over 2,400 businesses throughout the State of Minnesota. Many of its members are within Xcel

[9] Ex. 140, Heuer Opening Statement at 8.
[10] COMPANY'S FINAL ISSUES LIST (Oct. 7, 2014) (eDockets Doc. No. 201410-103651-01).

Energy's service territory. The MCC is involved in policy issues that affect business, including energy policy, on behalf of its members.

12. The Commercial Group is an association of large commercial operators of retail facilities and distribution centers in Minnesota, many of which are served by Xcel Energy. It is concerned with any rate increase to Xcel Energy's commercial customers.

13. The Energy CENTS Coalition (ECC) is a non-profit organization that promotes affordable utility service for low and fixed-income individuals. ECC intervened in this proceeding to protect the financial interests of low-income customers of the Company.

14. The Suburban Rate Authority (SRA) is a municipal joint powers association. Its members are suburban municipalities within the Twin Cities metropolitan area, and most of its members are served by Xcel Energy.

15. The Institutional Customer Intervention Group (ICI) is an ad hoc group of large industrial, commercial, and institutional customers that receive electric service from Xcel Energy and U.S. Energy Services, Inc. The outcome of this case could impact the ICI Group's production costs.

16. The Natural Resource Defense Council, Fresh Energy, Sierra Club, and the Izaak Walton League of America-Midwest Office (collectively, the Clean Energy Intervenors (CEI)) are non-profit organizations that share an interest in advancing resource choices that minimize or eliminate pollutant emissions, and maximize energy efficiency. The CEI supports policies designed to decrease electric consumption.

17. The American Association of Retired Persons (AARP) is a non-profit organization that advocates on behalf of people who are 50 years of age and older. AARP has 652,000 members in Minnesota, many of whom are residential electric customers of Xcel Energy. AARP intervened in this proceeding to protect the

financial interests of people aged 50 and over who are more vulnerable to increases in energy prices.

C. Procedural Background[11]

18. On October 3, 2013, the Company filed sales forecast data, as required by the Commission's Order in the Company's prior electric rate case (Docket No. E002/GR-12-961)[12] to be provided 30 days in advance of the filing of the Company's subsequent rate case.[13]

19. On November 4, 2013, the Company filed its Application to increase electric rates in Minnesota.[14] In its Application, the Company requested authority to increase electric rates through a MYRP pursuant to Minn. Stat. § 216B.16, subds. 1 and 19.[15] The Company structured its MYRP to be a two year proposal, with the first year revenue requirement calculated from a traditional test year (2014) and the second year (2015 Step) limited to specific capital additions and related costs.[16] The Company requested a two-year increase of $192.7 million, or 6.9 percent, in 2014, and $98.5 million, or 3.5 percent, in 2015 for a total increase of $291.2 million, or 10.4 percent based on present revenues.[17] The Company requested approval of an interim rate increase of 4.57 percent beginning January 3, 2014.[18]

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[11] All documents referenced to in this section are filed with the Department of Commerce eDockets system, Docket Number 13-868, and may be viewed through the eDockets Search at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showeDocketsSearch&showEdocket=true&userType=public.

[12] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 18, Docket E-002/GR-12-961 (Sept. 3, 2013) (*hereinafter* 2013 RATE CASE ORDER).

[13] Ex. 1, Pre-Filing Sales Forecast Data.

[14] Exhs. 12-19, Application Vol. 1-6 and Errata.

[15] Ex. 12, Filing Letter at 1.

[16] Ex. 12, Filing Letter at 1.

[17] Ex. 12, Filing Letter at 1.

[18] Ex. 12, Filing Letter at 1.

20. On December 12, 2013, the Commission held a hearing on interim rates and whether the Company's application should be deemed complete and referred to the Office of Administrative Hearings (OAH) for a contested case proceeding.[19]

21. On December 31, 2013, the Company submitted a filing required by Order Point 9 of the Commission's 2013 Rate Case Order, which required the Company to provide an analysis and report on the Sherco Unit 3 total costs, insurance recoveries, and costs not covered by insurance in its November 2013 rate case filing, and to provide the completed accounting and report by December 31, 2013.[20]

22. The Commission issued its Notice and Order for Hearing on January 2, 2014. On that same date, the Commission issued two other orders, one finding that the rate case filing was substantially complete,[21] and one setting an interim rate schedule for the duration of this proceeding.[22]

23. On January 2, 2014, when the Commission issued its Notice and Order for Hearing, the only parties to this proceeding were the Company, the Department, and the OAG.[23]

24. On January 31, 2014, the Company filed its "Bad Debt Study – Supplemental Information" in compliance with Order Point 31 from the Commission's 2013 Rate Case Order.[24]

25. Administrative Law Judge (ALJ) Jeanne M. Cochran held a Prehearing Conference on January 28, 2014. A First Prehearing Order was issued on February 14, 2014, setting forth the procedures for discovery and hearing preparation, as well as the dates of the evidentiary hearing. The First Prehearing Order also granted the

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[19] NOTICE OF COMMISSION MEETING (Dec. 6, 2013) (eDocket Doc. No. 201311-94124-07).
[20] Ex. 3, Pre-filing Sherco 3 Root Cause Report.
[21] ORDER ACCEPTING FILING, SUSPENDING RATES, AND REQUIRING SUPPLEMENTAL FILING (Jan. 2, 2014) (eDockets Doc. No. 20141-95050-01).
[22] ORDER SETTING INTERIM RATES (Jan. 2, 2014) (eDockets Doc. No. 20141-95066-01).
[23] NOTICE AND ORDER FOR HEARING (Jan. 2, 2014) (eDockets Doc. No. 20141-95049-01).
[24] Ex. 10, Bad Debt Study Supplemental Information.

petitions to intervene of the Commercial Group, ECC, the SRA, the ICI Group, and XLI.[25]

26. On February 7, 2014, the Company filed a letter agreeing to waive the statutory deadline for the Commission's decision such that the Commission's final decision in this proceeding will be issued on or about March 24, 2015.[26]

27. On March 5, 2014, the petitions to intervene of MCC and CEI were granted.[27]

28. On March 14, 2014, the petition to intervene of AARP was granted with limitations.[28]

29. On March 14, 2014, the petition to intervene of Minnesota Power was denied.[29]

30. On June 5, and June 6, 2014, the Intervenors filed Direct Testimony.[30]

31. Public hearings were held the week of June 23, 2014, according to the following schedule:

- June 23, 2014, Earle Brown Heritage Center, Minneapolis, and Sabathani Community Center, Minneapolis;

- June 24, 2014, West Minnehaha Recreation Center, St. Paul, and Woodbury Central Park, Woodbury;

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25 FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
26 WAIVER OF STATUTORY DEADLINE (Feb. 7, 2014) (eDockets Doc. No. 20142-96267-01).
27 ORDER GRANTING INTERVENTION TO THE MINNESOTA CHAMBER OF COMMERCE AND TO FRESH ENERGY, THE IZAAK WALTON LEAGUE, THE SIERRA CLUB, THE NATURAL RESOURCES DEFENSE COUNCIL, AND THE MINNESOTA CENTER FOR ENVIRONMENTAL ADVOCACY (March 5, 2014), (eDockets No. 20143-97071-01).
28 ORDER GRANTING PETITION TO INTERVENE OF AARP WITH LIMITATIONS (March 14, 2014)(eDockets Doc. No. 20143-97340-01). This Order limited AARP's participation to issues of rate design and decoupling, as well as any service quality issues that affect the unique interests of its members.
29 ORDER REGARDING PETITION TO INTERVENE OF MINNESOTA POWER (March 14, 2014), (eDocket Doc. No. 20143-97340-02). This Order stated that Minnesota Power could file an *amicus curiae* brief of up to 40 pages in length no later than Sept. 30, 2014.
30 FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01); *See* SECOND PREHEARING ORDER AND ORDER GRANTING MOTION FOR EXTENSION OF TIME (June 25, 2014) (eDockets Doc. No. 20146-100778-01).

- June 25, 2014, Civic Center, Mankato;

- June 26, 2014, Eden Prairie City Center, Eden Prairie; and

- June 27, 2014, Lake George Municipal Complex, St. Cloud.

32. The Parties filed Rebuttal Testimony on July 7, 2014.[31]

33. On July 16, 2014, a Joint Prehearing Conference was held by ALJ Cochran and ALJ Steve M. Mihalchick to ensure that issues related to the investments at the Monticello Nuclear Generating Plant were coordinated between this docket and the Monticello prudence investigation docket (Docket No. E002/CI-13-754 (Prudence Investigation)).[32]

34. On July 17, 2014, a Joint Prehearing Order was issued that held that the following issues would be addressed in this docket:

> (1) The issue of whether the Extended Power Uprate should be considered "used and useful" during 2014; and
>
> (2) The issue of the recovery and amortization of expenses from the Prudence Investigation.

35. The Parties filed Surrebuttal Testimony on August 4, 2014.[33]

36. On August 8, 2014, a Prehearing Conference was held to facilitate an orderly and efficient evidentiary proceeding.[34]

37. The evidentiary hearings were held on August 11-15, 2014, in the Commission's large hearing room in St. Paul, Minnesota.

38. On September 10, 2014, the Company filed an Issues List identifying all issues raised in the course of the rate proceeding and specifying which issues had been

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[31] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
[32] Transcript of July 16, 2014 Joint Prehearing Conference in Docket Nos. E002/GR-13-868 and E002/CI-13-754.
[33] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
[34] Transcript of August 8, 2014 Prehearing Conference.

resolved and which issues remained in dispute.[35] The same day, the Company also filed a Financial Adjustment Summary.[36]

39. On September 23, 2014, the Parties filed Initial Briefs.[37]

40. On September 30, 2014, Parties filed comments on the Company's Issues List.[38]

41. On October 7, 2014, the Company filed an updated version of the Issues List, incorporating the comments from the other parties.[39]

42. On October 14, 2014, the Parties filed Reply Briefs and Proposed Findings of Fact.[40]

D. Summary of Public Comments

43. Hundreds of written comments were filed by members of the public before the July 7, 2014 deadline.[41] In addition, approximately 100 people also provided oral comments during the seven public hearings that were held from June 23, 2014 to June 27, 2014 across the Company's service territory.

44. Members of the public raised a variety of specific concerns but the most frequently issue raised was about the size of the Company's proposed rate increases in 2014 and 2015.[42] Ratepayers commented that the proposed rate increases are excessive and would be difficult to afford on limited or set incomes.[43] Several members of the public also stated that they felt that they were being penalized for their conservation efforts with higher rates.[44] Ratepayers also commented that, as a

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[35] COMPANY DRAFT ISSUES LIST AND FINANCIAL SUMMARY (Sept. 10, 2014) (eDockets Doc. No. 20149-102963-01).
[36] COMPANY DRAFT ISSUES LIST AND FINANCIAL SUMMARY (Sept. 10, 2014) (eDockets Doc. No. 20149-102963-01).
[37] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
[38] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
[39] COMPANY FINAL ISSUES LIST (Oct. 7, 2014) (eDockets Doc. No. 201410-103651-01).
[40] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
[41] Tr. Vol. 1 at 43 (ALJ Cochran).
[42] Tr. Vol. 1 at 44 (ALJ Cochran).
[43] Tr. Vol. 1 at 44 (ALJ Cochran).
[44] Tr. Vol. 1 at 45-46 (ALJ Cochran).

regulated monopoly, Xcel Energy has no incentive to control costs and that the Company should do a better job at cost control.[45] Finally, ratepayers raised specific concerns about executive and employee compensation, corporate aviation costs, and naming rights costs.[46]

E. Legal Standard

45. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[47] A reasonable rate enables a utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in the capital market.[48] Minnesota law recognizes this principle when it defines a fair rate as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment.[49]

46. The Commission acts in both a quasi-judicial and quasi-legislative capacity in setting rates. It evaluates facts, including the claimed costs, and also evaluates the reasonableness of placing the burden of the costs on the ratepayers.[50] The Commission acts in a quasi-legislative capacity and has greater discretion with regard to rate design.[51] In contrast, the Commission is subject to the substantial evidence standard with respect to revenue issues.[52]

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[45] Tr. Vol. 1 at 46 (ALJ Cochran).
[46] Tr. Vol. 1 at 47 (ALJ Cochran).
[47] Minn. Stat. § 216B.03.
[48] Ex. 30, Tyson Direct at 17-21.
[49] Minn. Stat. § 216B.16.
[50] *In re Northern States Power Co.*, 416 N.W.2d at 722-723.
[51] *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n.*, 302 N.W.2d 5, 9 (Minn. 1980); *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n,* 312 Minn. 250, 260, 251 N.W.2d 350, 357 (Minn. 1977) ("Once revenue requirements have been determined, it remains to decide how, and from whom, the additional revenue is to be obtained.… The commission may then balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among customer classes… It is clear that when the commission acts in this area it is operating in a legislative capacity…").
[52] *In re Request of Intestate Power Co. for Authority to Change its Rates for Gas Service*, 574 N.W.2d 408, 413 (Minn. 1998); establishing the standard of review for revenue requirement under the substantial evidence test; *Hibbing Taconite Co.*, 302 N.W.2d at 9 ("The *St. Paul Chamber* case enunciated the PSC's two functions and the related standards of review. In applying those standards, we now hold that the establishment of a rate of return involves a factual determination which the courts will review under the substantial evidence standard.").

47. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change is just and reasonable.[53] In the context of a rate proceeding, the "preponderance of evidence" is defined as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considering together with the Commission's statutory duty to enforce the state's public policy that retail customers of utility services shall be furnished such services at reasonable rates."[54] Any doubt as to the reasonableness of the proposed rates is to be resolved in favor of the consumer.[55]

48. The general rule is that "the burden of proof rests on the party seeking to benefit from a statutory provision."[56] In *Northern States Power Company for Authority to Change its Schedule of Rates for Electric Services*, the Minnesota Supreme Court described the utility's burden of proof as follows:

> In evaluating the validity of a rate increase application, the Commission should apply the classic burden of proof analysis employed in civil cases in determining whether the utility has established the amount of a claimed cost as a judicial fact.[57]

49. The burden of proof in civil cases has two aspects: "the burden of persuasion and the burden of producing evidence."[58]

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[53] Minn. Stat. § 216B.16, subd. 4.
[54] *In re Northern States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).
[55] Minn. Stat. § 216B.03.
[56] *C.O. v. Doe*, 757 N.W.2d 343, 352 (Minn. 2008); *Reliance Life Ins. Co. v. Burgess*, 112 F.2d 234, 238 (8th Cir. 1940) ("It is a fundamental rule that the burden of proof in its primary sense rests upon the party who, as determined by the pleadings, asserts that the affirmative of an issue and it remains there until the termination of the action. It is generally upon the party who will be defeated if no evidence related to the issue is given on either side."); *See* Minn. Stat. § 216B.16, subd. 4.
[57] 416 N.W.2d 710, 722 (Minn. 1987); *In re Interstate Power Co.*, 419 N.W.2d 803, 807 (Minn. Ct. App. 1988),
[58] Minnesota Practice, Vol. 11, Evidence § 301.01 (2013). *See also Schaffer ex re. Schaffer v. Weast*, 546 U.S. 49, 56 (2005) (determining which party bears the burden of proof in an administrative hearing); Stockton East Water Dist. v. U.S., 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").

50. The burden of persuasion is "the duty of creating an affirmative belief on the part of the tribunal in the existence of the fact or facts in issue."[59] The burden of persuasion is generally fixed before the hearing and does not shift to the other party.[60] Here, the Company has the burden of persuasion, both as provided by Minn. Stat. § 216B.16, subd. 4, and under the general rule. 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."[61] This general rule applies both in administrative law proceedings and civil cases.[62]

51. The burden of production is "the duty of introducing evidence at a particular stage of a trial – of going forward with the evidence."[63] While the Company has the burden of proof, the burden of production may shift throughout a proceeding. The general rule is as follows:

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[59] 21 Dunnell Minn. Digest, Evidence § 13.01 (5th ed. 2006); *see Technology 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").

[60] Minnesota Practice, Vol. 11, Evidence § 301.01 (2013); Minn. R. Evid. 301 (2014) (presumptions shift "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 through the trial upon the party on whom it was originally cast."); *Commercial Molasses Corp. v. New York Tank Barge Corp.*, 314 U.S. 104, 110-11 (1941); *see e.g., Texas Dept. of Community Affairs v. Burdine*, 450 U.S. 248, 253 (1981) ("[t]he ultimate burden of persuading the trier of fact that the defendant intentionally discriminated against the plaintiff remains at all times with the plaintiff").

[61] 21 Dunnell Minn. Digest, Evidence § 13.03 (5th ed. 2006); *See also 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 a defendant, the plaintiff has met his burden of proof"); *Elk River Concrete Products Co. v. American Cas Co. of Reading, Pa.*, 129 N.W.2d 309, 314 (Minn. 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 (Minn. 1941) (finding that the "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 evidence to be expected of him").

[62] *E.g.*, *Rydberg v. Goodno*, 689 N.W.2d 310, 313 (Minn. Ct. App. 2004) (applying the court's rule from *Fidelity Bank & Trust Co v. Fitzimons*, 261 N.W.2d 586, 590 (Minn. 1977) and finding that plaintiff had established a prima facie case for pass-eligible status such that it was "unclear what more the commissioner [of human services] would have [plaintiff] prove," such that "at this point, the burden shifted to parties opposing pass-eligible status"); *In re Chicago Rys. Co.*, 175 F.2d 282, 281 (7th Cir. 1949) (finding that when a prima facie case is established by evidence and there is an "absence of explanatory or contradictory evidence" then "the finding shall be in accordance with the proof establishing the prima facie case").

[63] 21 Dunnell Minn. Digest, Evidence § 13.01 (5th ed. 2006). *See Technology Licensing Corp. v. Videotek, Inc.*, 545 F.3d 1316, 1327 (Fed. Cir. 2008); *Ryan v. Metropolitan Life Ins. Co.*, 298 N.W. 557, 560 (Minn. 1939) (discussing the differences between the burden of producing evidence and the burden of persuasion).

> A prima facie case shifts to the opponent of the one having the burden of proof, the burden of producing evidence to overcome it.[64]

52. In Minnesota, the statutes and Rules set forth specific requirements for a complete rate application that details, supports and ties out revenues, costs and investments. That filing, coupled with its testimony and other evidence in support of the filing, constitutes substantial evidence, which establishes the Company's prima facie case. Any portion of the prima facie case that is unrebutted must prevail as a matter of law.[65]

53. By establishing its prima facie case, the burden of producing evidence (as opposed to mere argument, conjecture, or policy disagreement) shifts to the other parties.[66] If the prima facie case is rebutted with such evidence then the Company still has the burden of persuasion, but, again, to establish a rebuttal to the prima facie case, the other parties bear the burden of producing actual evidence. And, such evidence must be competent and probative.[67]

54. In this case, the ultimate burden of proving the reasonableness of the proposed change in rates remains with the Company. But the burden of producing evidence to rebut the Company's initial case is on other parties.

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[64] 21 Dunnell Minn. Digest, Evidence § 13.03 (5th ed. 2006).

[65] *United States v. Ahrens*, 530 F.2d 781, 787 (8th Cir. 1976) (holding that the government satisfied its burden of proof to establish a prima facie case since the taxpayer failed to rebut the prima facie case, and therefore court was required to enter summary judgment in favor of the government).

[66] *Texas Dept. of Community Affairs v. Burdine*, 450 U.S. 248, 252-56 (1981) (explaining that if the plaintiff establishes a prima facie case, then the burden of production shifts to the defendant to rebut the presumption raised by the prima facie case. If the defendant does not rebut the prima facie case and the plaintiff's evidence is believed by the trier of fact, then the court must enter judgment for the plaintiff).

[67] *LaFavor v. American National Insurance Company*, 155 N.W.2d 286, 291 (Minn. 1967) ("[w]hile the evidence in proof of a crucial fact may be circumstantial, it must not leave it in the field of conjecture).

II. KEY DISPUTED ISSUES

A. Return on Equity (ROE) (Issue # 1)

55. The basic standards for the determination of return on equity (ROE) are found in the United States Supreme Court's decisions in *Hope*[68] and *Bluefield*[69] and in Minn. Stat. § 216B.16. The standards established in *Hope* and *Bluefield* require that the Company's ROE should be: 1) consistent with other businesses having similar or comparable risks; 2) sufficient to support credit quality and access to capital; and 3) sufficient to maintain financial integrity.[70] Minn. Stat. § 216B.16, subd. 6 requires the Commission to consider multiple factors when establishing the Company's ROE, including "the need of the public utility for revenue sufficient to enable it…to earn a fair and reasonable return upon [its] investment…."

56. Under all of the applicable standards, the ROE allowed by the Commission should be: 1) comparable to returns investors expect to earn on other investments of similar risk; 2) adequate to maintain and support the Company's credit and to attract debt and equity capital; and 3) sufficient to assure confidence in the Company's financial integrity.[71]

57. Establishing the ROE is a factual determination that is to be supported by substantial evidence.[72]

1. Market Conditions and the Multi-Year Rate Plan

58. The Company's expert witness, Mr. Robert B. Hevert, explained that interest rate environment has changed significantly since the Company's previous rate case.[73] Current long-term interest rates have risen significantly from the historic low

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[68] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).
[69] *Bluefield Waterworks Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*).
[70] *Hope*, 320 U.S. at 603-05; *Bluefield*, 262 U.S. at 692-95.
[71] Ex. 27, Hevert Direct at 7; *see also* Ex. 400, Amit Direct at 3.
[72] *Petition of Xcel Energy*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER, Docket No. E002/GR-06-1429 at 34 (September 10, 2007), (eDockets Doc. No. 4768622).
[73] Ex. 27, Hevert Direct at 11, 15.

levels observed in 2012 and 2013.[74] These increases are in part the result of uncertainty associated with the Federal Reserve's quantitative easing stimulus program; this uncertainty represents a meaningful risk to investors in general and a greater risk to investors in debt and equity securities of electric utilities.[75] The recent increases likely reflect investors' anticipation of the eventual "tapering" of the quantitative easing program.[76] Analyst projections indicate further interest rate increases in both the near and long-term.[77]

59. Mr. Hevert explained that the increased interest rates have been accompanied by a decrease in the stock value of utility companies.[78] Even though the prices for utility stocks do not move in lockstep with interest rates, these decreased stock values suggest an increase in the cost of equity.[79]

60. As a capital-intensive company that requires continual access to external sources of funds, the Company is exposed to the increased risks and costs resulting from market conditions such as interest rates.[80]

61. Anticipated increases in interest rates are especially important in light of the MYRP presented in this proceeding. Mr. Hevert stated that because interest rates and price instability are expected to increase during the term of the MYRP, investors necessarily will incorporate a larger risk premium as compensation for the risk that the Company is unable to recover increases in its market-required cost of equity during that longer period.[81]

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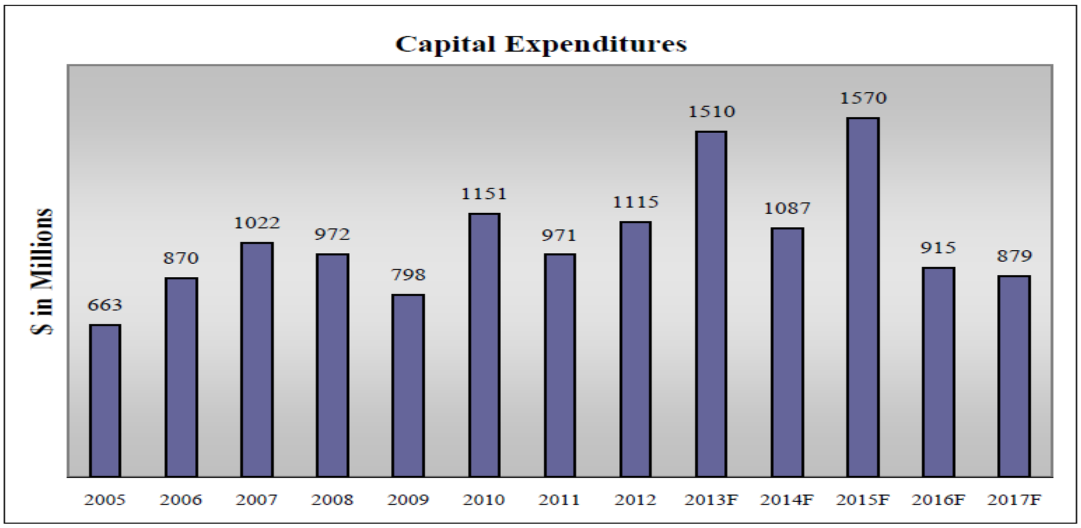
[74] Ex. 27, Hevert Direct at 11-12.
[75] Ex. 27, Hevert Direct at 10.
[76] Ex. 27, Hevert Direct at 10.
[77] Ex. 27, Hevert Direct at 11-12.
[78] Ex. 27, Hevert Direct at 12-13.
[79] Ex. 27, Hevert Direct at 13.
[80] Ex. 27, Hevert Direct at 15.
[81] Ex. 27, Hevert Direct at 52-53.

2. The Company's Capital Investments and ROE Realization

62. The Company remains in a period of very substantial capital investment, which began in 2005 and will continue through 2017. The Company has invested approximately $7.6 billion from 2005 through 2012, and projects additional capital expenditures averaging slightly less than $1.2 billion per year from 2013 through 2017,[82] as follows:



63. Investments through 2012 included the MERP projects, wind generation, nuclear Life Cycle Management and the Monticello extended power uprate, and transmission and other infrastructure.[83] To fund investments through 2013, the Company currently has approximately $4.2 billion in long term debt outstanding,[84] and has been reinvesting earnings at a rate of 85 percent for 2007 through 2013, with reinvestment of over 100 percent of earnings in 2005, 2006, and 2013.[85]

64. The Company will continue to invest capital, regardless of capital market conditions.[86] The projected capital expenditures will be needed to complete the

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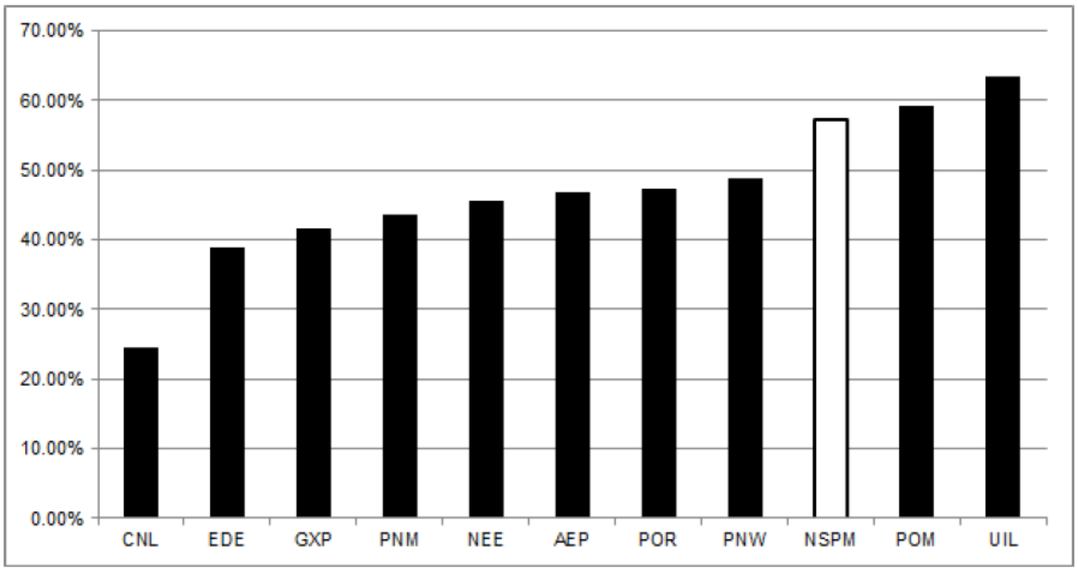
[82] Ex. 30, Tyson Direct at 5, 14, and Schedule 3.
[83] Ex. 30, Tyson Direct at 14.
[84] Ex. 31, Tyson Rebuttal at 5.
[85] Ex. 31, Tyson Rebuttal at 13.
[86] Ex. 30, Tyson Direct at 16; Ex. 31, Tyson Rebuttal at 10.

CapX2020 transmission project, the Prairie Island Unit 2 steam generator replacement, and several transmission and distribution infrastructure replacement projects.[87] These capital expenditures are needed to meet reliability standards and other compliance requirements and to support the infrastructure necessary to serve the Company's customers.[88]

65. The Company's projected capital expenditures are at the top of the range of comparable electric utilities:[89]



66. The Company's significant capital expenditures have been accompanied by a trend: in recent years, the Company has not achieved its authorized ROE.[90] The Company has not achieved its authorized ROE since 2007 for its Minnesota Electric Retail Jurisdiction, the NSPM Total Company Electric Utility, or Total Company Financial Reporting (Form 10-K) basis.[91] NSPM's weather-normalized ROEs have

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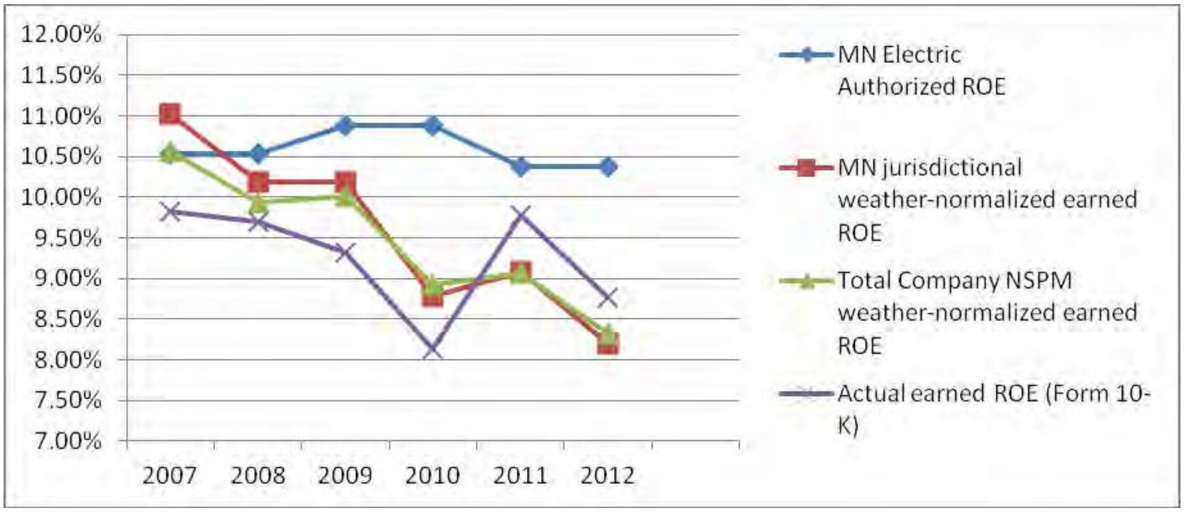
[87] Ex. 30, Tyson Direct at 16.
[88] Ex. 30, Tyson Direct at 5.
[89] Ex. 28, Hevert Rebuttal at 11 (comparing the Company's projected capital expenditures to Dr. Amit's FECG); *see also* Ex. 27, Hevert Direct at 46-47 (comparing the Company's projected capital expenditures to Mr. Hevert's Electric Proxy Group).
[90] Ex. 30, Tyson Direct at 14-15.
[91] Ex. 30, Tyson Direct at 14.

also been significantly below reasonable levels since 2009 and its actual ROEs have been significantly below reasonable levels since 2007:[92]



67. As shown above, since 2007, the Company's Minnesota jurisdictional weather-normalized earned ROE has decreased from approximately 11.00 percent (which was above its authorized ROE of 10.50 percent for one year in 2007) to less than 8.50 percent in 2012. For 2013, the Company's Minnesota jurisdictional weather normalized ROE was 8.22 percent.[93] This pattern of high capital expenditures and unreasonably low earned ROEs has caused the Company to submit rate case filings more frequently than the Company would have preferred.[94]

68. The Company will need regular access to capital markets to fund its planned levels of capital expenditures.[95] For example, NSPM plans to issue $300 million of long-term debt during 2014, to repay short-term debt incurred to fund its utility operations and construction program.[96]

69. Mr. Hevert explained that the Company's credit rating and outlook depend substantially on the extent to which rating agencies view the regulatory

[92] Ex. 30, Tyson Direct at 15, Chart 1.
[93] Tr. Vol. 3 at 167 (Heuer).
[94] Ex. 30, Tyson Direct at 15.
[95] Ex. 30, Tyson Direct at 16-17.
[96] Ex. 30, Tyson Direct at 16.

environment as being supportive.[97] The Commission's decisions in this proceeding, including the ROE that it authorizes, will affect the Company's ability to finance capital expenditures internally and will have a particularly strong effect on investor and rating agency perceptions of NSPM.[98] Investors and credit rating agencies are aware that NSPM has investments that are very heavily weighted toward its electric business.[99] They are also aware that NSPM's customers are concentrated in Minnesota, making the Minnesota retail electric jurisdiction NSPM's primary jurisdiction.[100] Rating agencies and bond and equity investors also know that the Commission is fully informed about NSPM's investment plans.[101] As a result, they will likely consider the Commission's decisions regarding the financial components of our overall ROR and electric rates as a reflection of the level of support for those investment plans.[102]

70. For example, in its August 12, 2013 Credit Opinion for NSPM, Moody's notes the importance of regulatory support in the context of capital expenditures:

> The continuation of this regulatory support, in particular in the 2014 electric rate case, is all the more important now as the company reaches the peak of its large capital program.[103]

Another example is that in response to the Commission's summer 2013 decisions, J. P. Morgan downgraded the Company's stock (and Barclay's expressed similar concern).[104]

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[97] Ex. 27, Hevert Direct at 16; Ex. 30, Tyson Direct at 17.
[98] Ex. 30, Tyson Direct at 18.
[99] Ex. 30, Tyson Direct at 18.
[100] Ex. 30, Tyson Direct at 18-19.
[101] Ex. 30, Tyson Direct at 19.
[102] Ex. 30, Tyson Direct at 19.
[103] Ex. 30, Tyson Direct at 23.
[104] Ex. 30, Tyson Direct at 21.

3. Determination of the Cost of Equity and Use of the DCF Models

a. Summary of the Company's and the Department's Analyses

71. While the cost of debt can be directly measured, the cost of equity is market-based and, therefore, must be estimated based on observable market information.[105]

72. The DCF model, which is based on the theory that a stock's current price represents the present value of all expected future cash flows, is widely used to estimate the cost of equity in regulatory proceedings and is typically applied in Minnesota.[106] In its simplest form, the DCF model expresses the cost of equity as the sum of the expected dividend yield and long-term growth rate.[107] Both the Company and the Department relied primarily on their Constant Growth DCF and Two Growth DCF results in arriving at their ROE recommendations.[108] The Two Growth DCF is applied when the mean growth rate of a particular company may be considered a high or low outlier relative to the proxy group.[109]

73. The Company, through Mr. Hevert, conducted a DCF analysis using (1) an Electric Proxy Group; and (2) a Combination Proxy Group.[110]

74. The Company also relied on the CAPM and Bond Yield Plus Risk Premium approaches.[111] The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security).[112] The Bond Yield Plus Risk Premium approach estimates the cost of equity as the sum of the premium over the return an investor would have earned as a

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105 Ex. 27, Hevert Direct at 28.
106 Ex. 27, Hevert Direct at 30.
107 Ex. 27, Hevert Direct at 30.
108 Ex. 27, Hevert Direct at 31-39; Ex. 400, Amit Direct at 6.
109 Ex. 27, Hevert Direct at 34.
110 Ex. 27, Hevert Direct at 18-27.
111 Ex. 27, Hevert Direct at 39.
112 Ex. 27, Hevert Direct at 39-40.

bondholder (the Equity Risk Premium) and the yield on a particular class of bonds.[113] The Company also considered other factors, including its capital expenditure program, its proposed partial decoupling mechanism, and the MYRP.[114]

75. Taking all of this information into consideration, the Company concluded that a rate of return on common equity in the range of 10.00 percent to 10.70 percent represents the required rate of return for NSPM in today's capital market environment.[115] Within that range, the Company recommended an ROE of 10.25 percent.[116]

76. In Rebuttal Testimony, the Company updated its DCF results, as shown below:[117]

	Low Growth Rate	***Mean Growth Rate***	***High Growth Rate***
Revised Electric Proxy Group Results			
30-Day Average	9.04%	9.97%	11.18%
90-Day Average	9.09%	10.02%	11.23%
180-Day Average	9.20%	10.13%	11.34%
Weighted Average Results (80% Revised Electric / 20% Combination)			
30-Day Average	9.02%	9.92%	11.03%
90-Day Average	9.09%	9.98%	11.10%
180-Day Average	9.12%	10.01%	11.13%

77. Based on these updated figures, the Company maintained its 10.25 percent ROE recommendation, and range of 10.00 percent to 10.70 percent.[118]

78. The Department, through Dr. Eilon Amit, conducted a DCF analysis using (1) a Final Electric Comparison Group (FECG); and (2) a Final Combination Comparison Group (FCCG).[119]

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113 Ex. 27, Hevert Direct at 44.
114 Ex. 27, Hevert Direct at 45-53.
115 Ex. 27, Hevert Direct at 55.
116 Ex. 27, Hevert Direct at 55.
117 Ex. 28, Hevert Rebuttal at 56.
118 Ex. 28, Hevert Rebuttal at 1-2, 54-58.

79. The Department relied on the CAPM approach as a check.[120] The Department assigned a weight of 60 percent to the FECG and 40 percent to the FCCG, concluding that the Company's required rate of return ranges from a low of 8.97 percent to a high of 10.62 percent.[121] Within that range, the Department recommended an ROE of 9.80 percent.[122]

80. In surrebuttal, the Department performed an updated DCF analysis based on updated dividend yields from June 7, 2014 to July 7, 2014, updated growth rates, adjustments to the FECG and FCCG, and other updated information.[123] The Department recommended a ROE of 9.64 percent, the midpoint of the updated range of 8.93 percent to 10.39 percent.[124]

b. Areas of Agreement Between the Company and the Department

81. Both the Company and the Department followed Commission practices relating to the methodology for their ROE analyses:

- They each used a combination of the constant growth DCF model and a Two-Growth DCF model, and analyzed current and expected dividend yield as part of those models;[125]
- They each used and weighted two groups: a group of electric companies and a group of combined gas and electric companies like the Company.[126]
- They each presented well-documented explanations of how they used screening criteria to select the companies for their electric and combination comparable groups.[127] These criteria

119 Ex. 400, Amit Direct at 8-22.
120 Ex. 400, Amit Direct at 37-42.
121 Ex. 400, Amit Direct at 43.
122 Ex. 400, Amit Direct at 43.
123 Ex. 403, Amit Surrebuttal at 3-11.
124 Ex. 403, Amit Surrebuttal at 2, 11.
125 Ex. 27, Hevert Direct at 29, 31-39; Ex. 28, Hevert Rebuttal at 6; Ex. 400, Amit Direct at 6.
126 Ex. 27, Hevert Direct at 18-27, 34; Ex. 28, Hevert Rebuttal, at 8; Ex. 400, Amit Direct at 8-22, 43; Ex. 443, Amit Opening Statement at 2.
127 Ex. 27, Hevert Direct at 18-27; Ex. 400, Amit Direct at 8-22.

were similar to criteria that the Commission has accepted in the past.[128]

- They each used earnings projections from Zacks, First Call, and Value Line to determine growth for the DCF model;[129]
- They each made adjustments for the recovery of flotation costs;[130]
- They each used the CAPM as a check on their DCF analyses;[131]
- They agreed no adjustment to the Company's ROE was necessary for decoupling;[132] and
- They agreed Construction Work in Progress (CWIP) did not need to be included in the rate base.[133]

c. Support for the Company's Recommended ROE

82. The Company presented a detailed explanation of the analysis underlying its proposed ROE of 10.25 percent.[134]

83. First, Mr. Hevert explained how he selected the groups of proxy companies. To select his Electric Proxy group, he began with a group of companies classified by Value Line as Electric Utilities, and then excluded companies that do not consistently pay quarterly dividends, companies not covered by at least two equity analysts, companies with lower-than-investment-grade bond or credit ratings, companies whose regulated operating income comprised less than 60 percent of the company's total operating income, companies whose regulated electric operating income over the last three years represented less than 90 percent of regulated operating income, and companies known to be party to a merger or other transaction.[135] The result was a group of seventeen companies.[136] He then excluded

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128 Ex. 27, Hevert Direct at 23.
129 Ex. 27, Hevert Direct at 31; Ex. 28, Hevert Rebuttal, at 7; Ex. 400, Amit Direct at 24.
130 Ex. 27, Hevert Direct at 35-39; Ex. 28, Hevert Rebuttal, at 8; Ex. 400, Amit Direct at 32-33.
131 Ex. 27, Hevert Direct at 39; Ex. 28, Hevert Rebuttal, at 8; Ex. 400, Amit Direct at 37-42.
132 Ex. 27, Hevert Direct at 51-52; Ex. 403, Amit Surrebuttal, at 26-28.
133 Ex. 27, Hevert Rebuttal at 47-48; Ex. 403, Amit Rebuttal at 16.
134 Ex. 27, Hevert Direct; Ex. 115, Hevert Opening Statement at 1-5; Tr. Vol. 1 at 54-101 (Hevert).
135 Ex. 27, Hevert Direct at 22-23.
136 Ex. 27, Hevert Direct at 23-24.

Edison International because of its recent financial problems, and he excluded IDACORP, Inc. and Hawaiian Electric Industries, Inc. to adhere to the Department's practice of excluding companies with mean DCF results below 8 percent.[137]

84. To select his Combination Proxy Group, Mr. Hevert began with a group of companies classified by Value Line as Electric Utilities and Natural Gas Utilities.[138] He applied a similar list of exclusions, and also excluded Xcel Energy because including it would be circular, resulting in sixteen companies.[139] He further excluded Consolidated Edison, Inc. and Sempra Energy in order to adhere to the convention of excluding companies with mean DCF results of less than eight percent.[140] The result was a Combination Proxy Group comprised of fourteen companies.[141]

85. Mr. Hevert explained the formulas underlying the Constant Growth DCF model.[142] For the price inputs to the Constant Growth DCF analysis, Mr. Hevert used the average daily closing prices for the 30, 90, and 180 trading days ended September 30, 2013.[143] For the dividend input, he used the annualized dividend per share as of September 30, 2013, with an adjustment to reflect quarterly dividend increases.[144] He then calculated the Constant Growth DCF results using each of three sets of growth estimates: Zacks, First Call, and Value Line.[145]

86. Mr. Hevert also calculated Two Growth DCF results. In his Two Growth DCF model, Mr. Hevert used the Zacks, First Call, and Value Line growth rates for the first two years, and then for the remaining "terminal period," he used the

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137 Ex. 27, Hevert Direct at 24.
138 Ex. 27, Hevert Direct at 25.
139 Ex. 27, Hevert Direct at 25-27.
140 Ex. 27, Hevert Direct at 27.
141 Ex. 27, Hevert Direct at 27.
142 Ex. 27, Hevert Direct at 30-31.
143 Ex. 27, Hevert Direct at 31.
144 Ex. 27, Hevert Direct at 31, 32-33.
145 Ex. 27, Hevert Direct at 31.

proxy group average growth rate, excluding outliers, as the Commission has used in other proceedings.[146]

87. Mr. Hevert then made an adjustment for flotation costs.[147] To do so, he divided the expected dividend yield by (1 – percentage flotation costs); this is the methodology used by the Commission in prior cases.[148]

88. In his CAPM model, Mr. Hevert used three different risk-free rates of return: the current 30-day average yield, the projected yield, and the long-term projected yield, on 30-year Treasury bonds.[149] Based on data from Bloomberg and Value Line, he developed a forward-looking estimate of the Market Risk Premium for use in the CAPM model.[150] He also used Beta coefficients derived from Bloomberg and Value Line.[151] The results of Mr. Hevert's CAPM approach were in the same general range as his Constant Growth DCF model.[152]

89. Mr. Hevert's Bond Yield plus Risk Premium approach demonstrated that the ROE should be between 10.33 and 10.90 percent.[153]

90. Mr. Hevert also considered the impact of the Company's capital expenditure program, and its proposed partial decoupling mechanism.[154]

91. Considering all of these factors, and using a weighting of 80 percent on the Electric Proxy Group and 20 percent on the Combination Proxy Group, Mr. Hevert concluded to the updated DCF results set forth above.[155] Mr. Hevert recommended an ROE of 10.25 percent.[156]

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146 Ex. 27, Hevert Direct at 34.
147 Ex. 27, Hevert Direct at 35-39.
148 Ex. 27, Hevert Direct at 38.
149 Ex. 27, Hevert Direct at 41.
150 Ex. 27, Hevert Direct at 41.
151 Ex. 27, Hevert Direct at 42.
152 Ex. 27, Hevert Direct at 43.
153 Ex. 27, Hevert Direct at 44-45.
154 Ex. 27, Hevert Direct at 45-53.
155 Ex. 27, Hevert Direct at 55.
156 Ex. 27, Hevert Direct at 55.

92. Mr. Hevert explained that a ROE of 10.25 percent is reflective of the business risks the Company faces in a rapidly changing environment, especially considering market conditions and the Company's capital investments.[157] Although the Company's investments affect customer rates, the Company has offered a mitigation plan to address these rate impacts.[158]

93. Mr. Hevert stated that by establishing the Company's ROE at the requested level, the Commission will be signaling to the investment community that it is supportive of the Company's investments to provide safe and reliable electric service while meeting the State's evolving energy policies.[159] He further noted that the current period also represents a peak of the Company's multi-year investment cycle and therefore it is necessary for the Company to obtain a reasonable cost of capital during this period to support the necessary investments.[160]

d. The Department's Recommended ROE

94. The differences between the Department's updated recommended ROE and the Company's requested ROE mainly result from two differences in the DCF analyses. First, for the price inputs to the Constant Growth DCF analysis, the Company used average daily closing prices for 30, 90, and 180 trading day periods,[161] whereas the Department used the closing prices for only a 30-day period.[162] Second, the Company used an 80/20 weighting of the electric and combination company groups,[163] whereas the Department used a 60/40 weighting.[164]

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157 Ex. 115, Hevert Opening Stmt. at 1.
158 *See* Ex. 99, Clark Direct at 26-30.
159 Ex. 27, Hevert Direct at 47-50.
160 Ex. 27, Hevert Direct at 47.
161 Ex. 27, Hevert Direct at 32; Ex. 28, Hevert Rebuttal at 55-56.
162 Ex. 400, Amit Direct at 24-25; Ex. 403, Amit Surrebuttal at 3.
163 Ex. 27, Hevert Direct at 21.
164 Ex. 400, Amit Direct at 43.

i. Time Period Used for Prices

95. The Department critiqued the Company's use of historical prices over periods longer than 30 days (*i.e.*, 90 trading days and 180 trading days).[165] But, the Company responded that the Department's reliance on a 30-day period is not appropriate because it does not take into account market volatility and was undertaken at a time when utility stocks were trading at aberrantly high levels. In other words, the Company's use of the longer periods prevents the results from being skewed by anomalous results, which is important considering the unstable market conditions in 2013.[166]

96. The Company's argument about the unreliability of the Department's 30-day snapshot due to market volatility was borne out by market activity: from Dr. Amit's Direct Testimony to his Surrebuttal Testimony, the average dividend yield for Dr. Amit's FECG fell by 54 basis points and the average dividend yield for his FCCG fell by 26 basis points.[167] These significant and sudden decreases in dividend yields were the result of the fact that utility stock prices were unusually high during the period when Dr. Amit calculated his DCF results.[168] Since July 2014, though, utility stock prices have declined relative to the overall stock market and moved more in line with historical levels.[169] This decline in utility stock valuations is consistent with the market expectation of increasing interest rates over the coming two years.[170]

97. The Commission has recently recognized that unstable market conditions may justify looking at data from more than a single 30-day period when

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[165] Ex. 400, Amit Direct at 57-58.
[166] Ex. 27, Hevert Direct at 32.
[167] *Compare* Ex. 400, Amit Direct at 30, 35 *to* Ex. 403, Amit Surrebuttal at 3.
[168] Ex. 115, Hevert Opening Statement at 2.
[169] Ex. 115, Hevert Opening Statement at 2.
[170] Ex. 115, Hevert Opening Statement at 2.

determining the ROE.[171] In addition, other regulatory commissions, including FERC, traditionally look at price data from periods longer than 30 days.[172]

98. In light of the fact that the ROE set by the Commission in this proceeding will remain in effect for two years, the Commission should not rely on the Department's updated analysis, because is based only on a one-month snapshot of the financial market during this period of non-representative market behavior exhibiting instability in the cost of equity.

ii. Weighting of Company Groups

99. The Department critiqued Mr. Hevert's 80/20 weighing of the Electric Proxy Group and the Combination Proxy Group.[173] Mr. Hevert explained that because this proceeding will be setting electric rates, and the Company's concentration in electric service is highly consistent with the Electric Proxy Group and Dr. Amit's FECG, the 80 percent weighting is actually conservative.[174]

100. The Company contended that the Department's 60/40 weighting of the FECG and FCCG gives too much weight to non-electric operations.[175] Dr. Amit's FECG includes companies which, on average, derived 90.00 percent of their net income from regulated electric utility operations.[176] Thus, it already incorporates companies that reflect proportions of regulated electric operations that are highly consistent with the Company.[177] There is no need for further weighting to the

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[171] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority To Increase Its Rates for Natural Gas Service In Minnesota*, Docket No. G007,011/GR-10-977 (Deliberation Sept. 25, 2014).

[172] *See, e.g.*, EL11-66-001, FERC OPINION 531 at 10 (June 19, 2014); *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. and *Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers*, Cases 08-E-0539 and 08-M-0618 at 121 (April 24, 2009); *Application of Public Service Company of New Mexico For A Revision Of Its Electric Service Rates*, Case No. 10-00086-UT, FINAL ORDER PARTIALLY APPROVING CERTIFICATION OF STIPULATION at 58 (July 28, 2011).

[173] Ex. 400, Amit Direct at 60.

[174] Ex. 28, Hevert Rebuttal at 18.

[175] Ex. 28, Hevert Rebuttal at 18.

[176] Company Initial Brief at 30.

[177] Ex. 28, Hevert Rebuttal at 19.

FCCG.[178] The purpose of this proceeding is to set electric rates, which suggests that there should be no reflection of the lower costs of capital of gas operations (through the combination company data).[179]

101. The Department critiqued Mr. Hevert's weighting on the basis that the investment risks of the electric comparable companies and the combination comparable companies are similar.[180] But, the record shows that there are significant differences between the DCF results for the electric comparable companies and for the combination comparable companies, suggesting that the investment risks of the two groups may not be similar.[181]

102. The Department also argued against the Company's 80/20 weighting on the basis that all of the Company's electric and combination comparable companies are identified under the same Value Line and SIC code categories.[182] However, these very general classifications do not establish comparability: the Value Line codes used by the Company established a universe of 48 electric companies and 59 combination companies[183] which Mr. Hevert reduced to a final comparable group of 14 electric companies and 14 combination companies.[184]

103. Ultimately, selection of the weighting is a subjective decision.[185] Both the Company and the Department presented reasonable weightings. Thus, both weightings should be considered in determining the ROE.

iii. Market Expectations and Other Utilities

104. The Department's recommended ROE of 9.64 percent would represent a significant reduction to the Company's currently authorized ROE of 9.83 percent.

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178 Ex. 28, Hevert Rebuttal at 20.
179 Ex. 27, Hevert Direct at 21.
180 Department Initial Brief at 27; Ex. 400, Amit Direct at 60.
181 Ex. 28, Hevert Rebuttal at Schedule 1 (30-day, 60-day, and 180-day mean DCF results are 16 – 27 basis points lower for the electric comparable group than for the combination comparable group).
182 Department Initial Brief at 28; Ex. 400, Amit Direct at 61.
183 Ex. 27, Hevert Direct at 22, 25.
184 Ex. 27, Hevert Direct at 25, 27.
185 Ex. 400, Amit Direct at 43-44.

Mr. David M. Sparby testified that a ROE of 9.64 percent would require the Company to reduce costs or under-earn its ROE in key areas.[186] Adverse market reaction can occur in response to a Commission decision that reflects a more difficult regulatory environment for the Company. Market considerations are among the factors for consideration by the Commission under Minn. Stat. § 216B.16, subd. 6.

105. The average ROE authorized for vertically-integrated utilities in 2014 is 9.84 percent, whereas the average ROE authorized for distribution-only utilities in 2014 is 9.51 percent.[187] The Commission recently authorized a 9.59 percent ROE for CenterPoint.[188] The business risks posed to distribution-only utilities and natural gas utilities are quite different than the risks that the Company, with its two nuclear generating plants, large transmission system, and significant ongoing capital expenditures, faces.

106. The Company's currently authorized ROE of 9.83 percent is in the lowest one-third of ROEs authorized from 2012 through May 2014 for utilities that provide generation, transmission and distribution services and in the lowest 39 percent of ROEs authorized from August 2013 through May 2014.[189] Moving downward to 9.64 percent would put the Company in the bottom 10 percent of ROEs since 2012, and within the bottom 20 percent of returns authorized since August 2013.[190]

107. The Company argued that authorizing the Department's recommended ROE of 9.64 percent would send a clear negative signal to investors that the Minnesota regulatory environment is not supportive of the Company's capital

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[186] Tr. Vol. 1 at 30 (Sparby).
[187] Ex. 225, Chriss Direct, at Schedule 3.
[188] *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 32, Docket No. GR-13-316 (June 9, 2014).
[189] Company Initial Brief at 26.
[190] Company Initial Brief at 24.

expenditure program, especially because it would be the second successive ROE decrease, and would represent a return near industry lows.

iv. The Department's DCF Calculations Closely Overlap with the Company's Requested ROE

108. The Commission has previously noted the significance of an overlap of ROE ranges in determining the ROE.[191] Both the Company's requested 10.25 percent ROE and the currently authorized 9.83 percent ROE are within the Department's DCF range for the Final Electric Comparison Group.[192] Even if the Commission used the Department's approach of a 30-day period and a 60/40 weighting, the results for the period ending May 30, 2014 is 9.86 percent.[193] The overlap between the Department's figures and the Company's analysis further demonstrates that the Company's proposed ROE of 10.25 is reasonable.

e. Other ROE Proposals

109. The ICI, through Mr. Glahn, recommended that the Commission set the Company's ROE at 9.00 percent.[194] There were inconsistencies and errors in how Mr. Glahn selected his comparable companies;[195] in particular, the screening criteria he used to select a proxy group were flawed because they included companies with substantial unregulated operations.[196] In response to questions from the Department, Mr. Glahn was unable to explain how he had selected his comparable companies.[197]

110. Mr. Glahn applied four DCF analyses, but the Company argued that all were flawed because (1) three contained a mismatch between the expected growth rates used to calculate the expected dividend yield and the expected growth rate of the

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[191] *In the Matter of Otter Tail Power Company*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 59, Docket No. E017/GR-07-1178 (Aug. 1, 2008); *In the Matter of Northern States Power Company*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 11-12, Docket No. E002/GR-08-1065 (Oct. 23, 2009).
[192] Ex. 400, Amit Direct at 37.
[193] Ex. 28, Hevert Rebuttal at Schedule 1, pages 1 and 4.
[194] Ex. 250, Glahn Direct at 23; Ex. 251, Glahn Surrebuttal at 4.
[195] Ex. 402, Amit Rebuttal at 3-6; Ex. 443, Amit Opening Statement at 3.
[196] Ex. 28, Hevert Rebuttal at 34.
[197] Tr. Vol. 3 at 118-134 (Glahn).

DCF; (2) all contain companies with unreasonably low ROEs; (3) he wrongly used short-term rather than long-term expected growth rates; and (4) he refused to make any allowance for flotation costs.[198] Two of his DCFs used a "sustainable growth" analysis that has not been accepted by the Commission in any prior Company rate case.[199] Historical market data and independent research also indicate that Mr. Glahn's sustainable growth model is unreliable.[200]

111. All of the growth rates on which Mr. Glahn relied were dividend growth rates, provided solely by Value Line.[201] But, analysts and investors focus on earnings growth, which indicates that earnings growth is the appropriate measure for the DCF model.[202] Prior research indicates that investors rely on analysts' earnings growth projections in valuing equity securities.[203]

112. Mr. Glahn pointed to three rate cases from other states in which the authorized ROE was 9.75 percent or lower, but failed to acknowledge nine other instances where companies received ROEs of 10.00 percent or higher.[204]

113. The Commercial Group did not perform an independent analysis of the cost of equity.[205] However, through Mr. Chriss, the Commercial Group stated that the Company's recommended 10.25 percent ROE was too high, noting that other commissions had awarded ROEs for vertically integrated utilities that averaged 10.3 in 2012-2014 and were 9.84 percent in 2014.[206] But, Mr. Chriss relied on outdated data.[207] Based on Mr. Chriss' approach, the average authorized ROE for vertically

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198 Ex. 402, Amit Rebuttal at 2-13; Ex. 443, Amit Opening Statement at 3; Ex. 28, Hevert Rebuttal at 35-41; Tr. Vol. 4 at 40-42 (Amit).
199 Ex. 28, Hevert Rebuttal at 33, 37.
200 Ex. 28, Hevert Rebuttal at 37.
201 Ex. 250, Glahn Direct at 20-21.
202 Ex. 28, Hevert Rebuttal at 36.
203 Ex. 28, Hevert Rebuttal at 38, *citing* Roger A. Morin, PhD, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 298-303.
204 Ex. 28, Hevert Rebuttal at 32.
205 Ex. 28, Hevert Rebuttal at 45.
206 Ex. 225, Chriss Direct at 8-9.
207 Ex. 402, Amit Rebuttal at 15.

integrated utilities has been approximately 10.00 percent, which is within the Company's recommended range.[208]

114. The Commercial Group further recommended that if CWIP is included in the rate base, the ROE should be reduced because CWIP shifts risk from the Company to ratepayers.[209] Both Dr. Amit and Mr. Hevert disagreed with the Commercial Group position regarding CWIP, noting the Commission's long-standing policy regarding CWIP, which indicates that the market had already taken that position into account.[210] Mr. Hevert explained that recovery of CWIP is commonly allowed by regulatory commissions.[211]

115. The AARP recommended that if decoupling is approved by the Commission, a 10-basis point reduction in ROE should be made or the ROE should be set at the low end of the range of reasonable ROEs.[212] The AARP stated that a number of utility Commissions have decided to lower ROE because of decoupling.[213]

116. Both the Department and the Company disagreed with this recommendation regarding decoupling.[214] Moreover, the AARP's recommendation is based on a selective review of decisions by other commissions, and ignores the fact that most commissions do not make an adjustment for decoupling.[215] A Brattle Group study concluded that there is no significant difference in the cost of capital between electric utilities with and without decoupling.[216] The issue is how the Company compares to the comparable companies, not how decoupling may affect the Company on a stand-alone basis.[217] Mr. Hevert agreed with Dr. Amit and explained

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208 Ex. 28, Hevert Rebuttal at 47.
209 Ex. 225, Chriss Direct at 11.
210 Ex. 28, Hevert Rebuttal at 47-48; Ex. 402, Amit Rebuttal at 16.
211 Ex. 28, Hevert Rebuttal at 48.
212 Ex. 310, Brockway Direct at 18; Ex. 311, Brockway Rebuttal at 18.
213 Ex. 311, Brockway Rebuttal at 18.
214 Ex. 28, Hevert Rebuttal at 49-54; Ex. 403, Amit Surrebuttal at 27.
215 Ex. 28, Hevert Rebuttal at 53; Ex. 29, Hevert Surrebuttal at 2-7.
216 Ex. 28, Hevert Rebuttal at 52; Ex. 403, Amit Surrebuttal at 27.
217 Ex. 403, Amit Surrebuttal at 28.

that relative risk compared to other comparable companies is the significant point.[218] Likewise, the CEI, through Mr. Cavanaugh, recommended that if the Commission approves a decoupling mechanism in this case, it should not change the Company's ROE for any reasons associated with the adoption of decoupling.[219]

4. Conclusion

117. The Company's recommended ROE of 10.25 percent is reasonable and appropriately addresses the effects of unsettled stock prices and the mandatory two-year effect of the ROE in this case. The Company's ROE is also comparable to other vertically-integrated utilities and takes into consideration a broader range of information than just the results of the Department's analysis of data from June 7, 2014, to July 7, 2014.

B. Monticello LCM/EPU Project – Used and Useful (In-Service Date) (2014 and/or 2015 Step) (Issue #2)

1. Background

118. The Monticello nuclear power generating plant (Monticello) has been in operation since 1971. Under its original license from the Nuclear Regulatory Commission (NRC), Monticello was only licensed to operate until 2010. In 2006, the Company obtained a license extension from the NRC allowing the plant to operate until 2030.[220]

119. The Monticello Life Cycle Management and Extended Power Uprate program (LCM/EPU Program) was a complex project undertaken to prepare the plant for its 20-year extended operating life while increasing the plant's capacity from 600 to 671 megawatts (MW).[221]

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[218] Ex. 28, Hevert Rebuttal at 49; Ex. 29, Hevert Surrebuttal at 7-8; Tr. Vol. 1 at 83, 86, 93-94 (Hevert).
[219] Ex. 290, Cavanaugh Direct at 5-6, 12; Ex. 294, Cavanaugh Rebuttal at 6; Tr. Vol. 3 at 61, 69-71 (Cavanaugh).
[220] Ex. 51, O'Connor Direct at 16.
[221] Ex. 51, O'Connor Direct at 15.

120. In 2008, the Company filed a License Amendment Request (LAR) with the NRC to increase or uprate the plant's capacity to 671 MW. That same year, the Company requested a Certificate of Need from the Commission to increase the plant's capacity to meet growing demand needs.[222]

121. In February 2009, the Commission approved the Certificate of Need for the uprate.[223]

122. The Company stated that the LCM and EPU are an integrated project (LCM/EPU Program) and were managed as such.[224] The LCM/EPU Program was implemented over approximately eight years, and replaced nearly all of the components that support the reactor and power generation equipment.[225]

123. The Company included costs for the LCM/EPU Program in its 2013 rate case. In that case, the ALJ concluded that the EPU portion of the LCM/EPU Program was not in service for purposes of rate setting "because the Company does not have the NRC license amendment required to operate at uprated EPU level."[226] The ALJ attributed 41.6 percent of the LCM/EPU Program costs to the EPU based on the allocation of costs used by the Company during the 2008-2009 Certificate of Need proceeding.[227]

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222 *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate,* PETITION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE MONTICELLO NUCLEAR GENERATING PLANT FOR EXTENDED POWER UPRATE, Docket No. E002/CN-08-185 (Feb. 14, 2008).

223 *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate,* ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT, Docket No. E002/CN-08-185 (Jan. 8, 2009).

224 Ex. 51, O'Connor Direct at 16; Ex. 53, O'Connor Rebuttal at 15-16.

225 Ex. 51, O'Connor Direct at 15.

226 *In the Matters of the Application of the Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION at ¶ 79, Docket No. E-002/GR-12-961(July 3, 2013)(emphasis added)(*hereinafter* ALJ REPORT IN 2013 RATE CASE).

227 ALJ REPORT IN 2013 RATE CASE at 17 ("The 41.6 percent apportionment of costs between the EPU and LCM represents the Company's own estimate of the proportion of costs attributable to the EPU part of the project. While the Company maintains that the estimate was an early, high level figure, the Company has not produced an incremental cost study or any other reliable accounting study to show that the estimate is no longer reasonable.")

124. The Commission accepted the ALJ's recommendation and concluded that the EPU portion of the Monticello LCM/EPU Program was not yet "used and useful" for purposes of the 2013 test year, and suggested that the Company may be able to recover costs once the EPU is licensed by the NRC:

> The Commission agrees with the ALJ that only the LCM portion of the LCM/EPU project is used and useful. The Commission also agrees that 41.6% is the portion of the project properly attributable to <u>the Extended Power Uprate, which cannot serve ratepayers until it is licensed by the NRC</u>.... The Commission therefore determines that 41.6% of the LCM/EPU costs for 2011 and 2012 additions added to the rate base in this case, 41.6% of 2013 May plant addition costs, and 100% of Nuclear Regulatory Commission license fees should be moved from plant in-service to CWIP, as well as the related depreciation reserve, deferred taxes, depreciation expense, AFUDC, and any other applicable costs. The Company may be allowed to recover those costs in future rate cases once the EPU is in service, subject to the plant being used and useful and subject to a determination that the costs – including cost overruns – were prudent.[228]

125. The Commission also deferred a review of the reasonableness of the underlying costs of the Monticello LCM/EPU Program to a separate prudence proceeding (Docket No. E002/CI-13-754 (Prudence Investigation)).[229]

126. In December 2013, the Company received NRC approval of the EPU license amendment that allowed the plant to begin the power uprate ascension.[230]

127. In March 2014, the plant operated at 640 MW for approximately 20 days.[231]

128. In March 2014, the Company received the MELLLA+[232] license amendment which was required to achieve uprate above 640 MW.

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[228] 2013 RATE CASE ORDER at 18.
[229] 2013 RATE CASE ORDER at 19-20.
[230] Ex. 53, O'Connor Rebuttal at 4.
[231] Tr. Vol. 1 at 231 (O'Connor).

129. With receipt of the LAR approvals for both the EPU and the MELLLA+, since March 2014 Monticello has been operating under an amended license that allows it to operate up to approximately 671 MW.[233]

130. Prior to operating at the new 671 MW level, the Company must first complete the power ascension process.[234] Power ascension is a prescribed acceptance testing process required by the NRC, and is a necessary element to support and evaluate nuclear plant operations and output during the power uprate startup phase.[235] The license amendments for the power uprate require ascension monitoring and testing to ensure the safe, reliable operation of the plant.[236]

131. During the evidentiary hearing, Company witness Mr. Timothy J. O'Connor stated that the plant is currently operating at 600 MW. Mr. O'Connor also testified that he anticipates that the plant will complete its power ascension testing protocol and fully ascend to 671 MW by the end of 2014.[237]

132. The July 17, 2014 Joint Prehearing Order issued in this rate case and the Prudence Investigation requires that the prudence of total Program costs and the division of LCM/EPU Program costs between the LCM and EPU are to be addressed in the Prudence Investigation.[238] The same Prehearing Order further notes that the issues to be decided in this rate case proceeding are: (i) whether the EPU aspect of the Program should be considered "used and useful" for purposes of 2014 and/or 2015

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232 MELLLA+ stands for "Maximum Extended Load Line Limit Analysis." MELLLA+ is an engineering analysis that provides for greater operational flexibility, permits more efficient reactor startup, maximizes fuel utilization, and improves fuel cycle economics. Ex. 51, O'Connor Direct at 20.

233 Ex. 53, O'Connor Rebuttal at 5.

234 Ex. 53, O'Connor Rebuttal at 5-6.

235 Ex. 53, O'Connor Rebuttal at 5-6.

236 Ex. 53, O'Connor Rebuttal at 5-6.

237 Tr. Vol. 1 at 232, 235 (O'Connor).

238 JOINT PREHEARING ORDER at 2, Docket Nos. E-002/GR-13-868 and E-002/CI-13-754 (July 17, 2014) (eDockets Doc. No. 20147-101591-01).

rates; and (ii) how expenses from the Prudence Investigation should be recovered and amortized.[239]

2. Parties' Positions

a. MCC's Position

133. The MCC proposed to treat the delay in ascending fully to 671 MW similar to a mechanical failure, consistent with the Commission's 2013 decision regarding treatment of Sherco Unit 3.[240] This would require the Company to: (i) remove depreciation and direct expenses related to the Monticello EPU from the 2014 test year and amortize them over the life of the facility; (ii) remove increased replacement fuel and power costs ($11.1 million) and allow the Company to recover the costs over the life of the facility; and (iii) require the Company to provide status updates of the ascension to the 671 MW uprate level.[241]

134. The MCC's proposal reduces 2014 test year revenue requirements by $12.227 million and increases 2015 Step revenue requirements by $11.680 million, subject to further adjustment depending on the Commission's decisions in the Monticello Prudence Investigation.[242]

135. The Department opposed MCC's proposal for several reasons: (1) the Company has not shown that the EPU will be used and useful in 2014; (2) neither the Company nor MCC has shown that deferral of costs to periods outside of the 2014 test year is reasonable; and (3) MCC's proposal would allow recovery of 2014 EPU costs from ratepayers, with a return, even though ratepayers are not receiving a benefit from the EPU, while it would defer the costs of fuel and replacement power that ratepayers are using and from which they are receiving a benefit.[243]

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239 JOINT PREHEARING ORDER at 2, Docket Nos. E-002/GR-13-868 and E-002/CI-13-754 (July 17, 2014) (eDockets Doc. No. 20147-101591-01).
240 Ex. 341, Schedin Rebuttal at 8.
241 Ex. 341, Schedin Rebuttal at 9.
242 Tr. Vol. 3 at 141, 152-53 (Heuer); Ex. 90, Heuer Rebuttal at Schedule 17.
243 Department Initial Brief at 91-92.

136. During the evidentiary hearing, the Company accepted the MCC's proposal.[244] The Company contended that the MCC's approach reasonably reflects the current status of Monticello and balances the interests of all stakeholders by recognizing that the EPU is used and useful even though the plant has not operated at full uprate capacity.[245]

137. The Company also stated that the MCC's approach also best reflects that the causes of delaying full ascension are not licensing or operational issues, but rather data issues the utility is in the process of reconciling for the benefit of all stakeholders.[246]

138. The Company further noted that the MCC's proposal also has the benefit of treating the fuel clause and rate base issues in a reasonable manner by offering customers a reduction in rate base that would offset the cost of alternative replacement capacity.[247] As such, construction cost recovery is deferred and recovery of replacement fuel costs are spread over a longer period, reducing the overall impact of the Program delays on customers.

139. The Company disagreed with the Department's characterization that the MCC's proposal may require deferral approvals from the Commission that the Parties have not requested in this proceeding.[248] The Company stated that the MCC's proposal is similar to the Commission's treatment of costs in its 2013 rate case with respect to the extended Sherco 3 outage, where the Commission did not require a deferred accounting petition.[249] Rather, the Company noted that in the 2013 rate case, the Commission recognized that "the task at hand is to equitably balance the interests

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[244] Ex. 134, Clark Opening Statement at 1; Ex. 140, Heuer Opening Statement at 2.
[245] Ex. 134, Clark Opening Statement at 1.
[246] Company Initial Brief at 37.
[247] Ex. 342, Schedin Surrebuttal at 4-5.
[248] Company Initial Brief at 40.
[249] Company Initial Brief at 40 *citing* 2013 RATE CASE ORDER at 23.

of the ratepayers and the shareholders"[250] and struck an appropriate balance between those interests based on the facts in that record.[251]

b. XLI's Position

140. XLI argued that the Monticello EPU will not be used and useful until the plant is operating at 671 MW.[252] XLI recommended that the Commission make a proportional adjustment based on the date when the plant achieves 671 MW. As the Company estimated that the plant will achieve full operation in December 2014, XLI recommended that 11/12ths of the EPU costs ($28.6 million) be excluded from the 2014 revenue requirements.[253]

141. The Company contended that XLI's proposal to allow only 11/12ths of the Monticello LCM/EPU project costs into rate base does not reflect how rate base is calculated.[254] The Company noted that it has historically used beginning of year/end of year (BOY/EOY) averages for test year rate base determination.[255] It would be inappropriate to use a 13-month average for this one capital project while using a BOY/EOY average for all other forecasted rate base items.[256]

142. The Department also disagreed with XLI's position. The Department argued that because the Company has failed to demonstrate that the uprate is used and useful or that it is likely to be used or useful by the end of 2014, there is no reasonable basis to allow any EPU-related costs in 2014 rates.[257]

c. Department's Position

143. The Department recommended that because the Company has not shown that the EPU is or will be used and useful by the end of 2014, the revenue

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[250] 2013 RATE CASE ORDER at 22.
[251] Company Initial Brief at 40.
[252] Ex. 260, Pollack Direct at 22.
[253] Ex. 260, Pollack Direct at 22-23.
[254] Ex. 94, Perkett Rebuttal at 46.
[255] Ex. 94, Perkett Rebuttal at 46.
[256] Ex. 94, Perkett Rebuttal at 46.
[257] Department Initial Brief at 93.

requirement should be reduced by $31.284 million such that 2014 depreciation expense and rate base return on the Monticello EPU are excluded from the 2014 test year.[258]

144. For the 2015 Step, assuming that plant is operating at 671 MW by January 2015 and the NRC has approved the plant to operate at this level, the Department recommended rate base treatment and recovery of associated depreciation costs.[259]

145. If the plant is not operating at 671 MW by January 2015 and the NRC has not approved the plant to operate at this level, the Department recommended that the Commission require the Company to refund any amounts collected in rates through the refund mechanism for the MYRP.[260]

d. Company's Position

146. The Company argued that if MCC's proposal is not accepted, the Monticello LCM/EPU Program should be considered used and useful in 2014.[261] The Company argued that with the receipt of all necessary NRC licenses amendments to operate at EPU levels, the LCM/EPU should be viewed as the unified project that it is, comprised of common plant utilized for both LCM and EPU purposes.[262]

147. The Company stated that completion of the ascension process is not a prerequisite to in-servicing the LCM/EPU, as the capital investment has been dedicated to public use and it should be expected that less than full performance of the plant would occur as systems are checked and validated.[263]

148. The Company pointed out that since the Commission's decision in the Company's last rate case there several important factual changes that have occurred

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[258] Ex. 450, Campbell Opening Statement at 3.
[259] Ex. 450, Campbell Opening Statement at 3-4.
[260] Ex. 450, Campbell Opening Statement at 3-4.
[261] Company Initial Brief at 42.
[262] Company Initial Brief at 41.
[263] Company Initial Brief at 40-41 citing *State ex rel. Utilities Comm'n v. Eddleman*, 358 S.E.2d 339, 352 (N.C. 1987) and *State ex rel. Missouri Public Service Co. v. Fraas,* 627 N.W.2d 882 (Mo. App. 1982).

that warrant a finding in this case that the EPU is "used and useful." These include: (1) the Company has now received all NRC licenses and amendments necessary to operate at uprate levels, including our EPU license amendment and MELLLA+ license;[264] (2) the Company is using all of the assets implemented as part of the LCM/EPU Program, resulting in higher safety margins and more efficient baseline output for customers;[265] (3) the plant has achieved a partial uprate, ascending to 40 of the additional 71 MW additional capacity expected from the Program;[266] and (4) the Company anticipates achieving full ascension by the end of 2014, through the relatively normal process of validating post-licensing data for the NRC.[267] As a result, the Company stated that the undisputed record evidence establishes not only that all assets are in use, but also that the Company has all licensing necessary to operate at uprate levels, has begun the ascension process and achieved 56 percent of the EPU capacity, and expects to achieve full ascension in 2014.[268]

149. Further, the Company noted that the Department's used and useful analysis depends on the assumption that it is possible and appropriate split LCM and EPU equipment such that one can designate certain assets or expenditures as not "used and useful" until the plant fully ascends.[269] The Company explained that the LCM/EPU split used in its prior rate case was intended to recognize that the Company had not yet procured the license amendments necessary to operate at uprate conditions, but this split is no longer relevant to a "used and useful" analysis.[270] As Mr. O'Connor discussed in hearings and pre-filed testimony in some length,[271] the NRC uprate licensing obtained by the Company was not limited to certain assets or

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264 Tr. Vol. 1 at 227 (O'Connor); Ex. 53, O'Connor Rebuttal at 4; Ex. 100, Clark Rebuttal at 23-24.
265 Tr. Vol. 1 at 220 (O'Connor); Ex. 53, O'Connor Rebuttal at 14; Ex. 100, Clark Rebuttal at 24.
266 Tr. Vol. 1 at 231 (O'Connor); Ex. 53, O'Connor Rebuttal at 10; Ex. 100, Clark Rebuttal at 24.
267 Tr. Vol. 1 at 231-233 (O'Connor); Ex. 55, O'Connor Surrebuttal at 5.
268 Company Initial Brief at 42.
269 Company Initial Brief at 38-39.
270 Company Initial Brief at 38-39.
271 Tr. Vol. 1 at 220 (O'Connor); Ex. 53, O'Connor Rebuttal at 14.

equipment, and it is not possible to identify standalone systems that are operational solely upon receipt of the license.

150. The Company explained that the plant as a whole is operating more safely and efficiently, and the plant as a whole will operate at increasing levels as output increases. The Company pointed out that while the ascension process is underway, the Company has "gained some efficiencies with some of the equipment that's already been replaced as part of the lifecycle management EPU; and we're operating a little bit better, in terms of total output, now that those modifications have been completed."[272] Moreover, "[t]oday, the plant is achieving over 90% of its potential [and] [i]t has already reached 95% of its potential safely…."[273]

3. The Used and Useful Standard

151. Under Minnesota law, just and reasonable rates include a fair and reasonable return upon the investment in property which is "used and useful" in rendering service to the public.[274]

152. To establish that property is "used and useful," the utility has the burden to prove: "(1) that the property [will be] 'in service;' and (2) that it [will be] 'reasonably necessary' to the efficient and reliable provision of utility service."[275] "The thing devoted by the investor to the public use is not specific property, tangible and intangible, but capital embarked in the enterprise."[276]

153. The "used and useful" standard is not a bright line test; rather, the determination of whether property is "useful" requires consideration of what is reasonable given the policy considerations and factual circumstances surrounding any

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272 Tr. Vol. 1 at p. 245 (O'Connor).
273 Ex. 53, O'Connor Rebuttal at 15.
274 Minn. Stat. § 216B.16, subd. 6.
275 *Senior Citizens Coalition v. Minnesota Public Utilities Commission,* 355 N.W.2d 295, 300 (Minn. 1984).
276 *State of Missouri ex. Rel. Southwestern Bell Telephone Company v. Public Service Commission of Missouri et. al.*, 262 U.S. 276, 290-291 (1923) (Brandies, J. concurring).

given capital asset.[277] "[I]t must be re-emphasized that the "used and useful" concept, if administered inflexibly and without regard to other equitable and policy considerations, may fail the interests of both the electric utility industry and its ratepayers."[278]

154. For purposes of this case, it is notable that the "used and useful" standard does not require property to be used to its full capacity or maximum benefit at all times to be considered used and useful.[279]

155. Moreover, the "used and useful" standard does not require immediate provision of benefits to customers; rather, as the United States Energy Administration has noted, the "used and useful" standard requires that "an asset currently provide or be capable of providing a needed service to customers."[280]

4. Conclusion

156. MCC's proposal presents a reasonable approach and is consistent with the Commission's decision regarding the Company's extended Sherco 3 outage. The MCC's approach should be adopted for recovery of costs for the EPU portion of the Monticello LCM/EPU Program, with the final adjustment to be determined by the Commission's decisions in the Monticello Prudence Investigation.

157. If the Commission decides not to adopt the MCC's proposal, the EPU portion of the Monticello LCM/EPU Program should be considered "used and

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[277] *In re Connecticut Light & Power Co.*, Connecticut Department of Public Utility Control Docket, No. 97-05-12 1997 WL 866679 ** 8-9, 19-21 (December 31, 1997) (*Connecticut Light & Power Decision*) (citing *Pennsylvania Public Utility Comm'n v. Metro. Edison Co.*, 37 PUR4th 77, 86 (1979)).

[278] Order No. 298, *Construction Work in Progress for Public Utility; Inclusion Costs in Rate Base,* [1982-1985 Regs. Preambles] F.E.R.C. Stats. & Regs. r[30,455, at 30,507, 48 Fed. Reg. 24,323 (1983). *aff'd in part, vacated and remanded in part, Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327 (D.C. Cir. 1985). *See also Consolidated Gas Supply Corp. v. FPC*, 520 F.2d 1176, 1185 (D.C. Cir. 1975) ("The legal system does not compel rigidity, or bureaucratic inflexibility, least of all in the area of energy policy where flexibility may be essential to the public interest.").

[279] *See City of Evansville v. Southern Indiana Gas and Electric Co.*, 167 Ind. App. 472, 515-20, 339 N.E.2d 562, 589-91 (1975) (cited in *Senior Citizens Coalition*, 355 N.W.2d at 300).

[280] U.S. Energy Information Administration Glossary, available online at http://www.eia.gov/tools/glossary/index.cfm?id=U (last visited on Sept. 17, 2014) (emphasis added).

useful" as these assets and systems are fully in use and benefiting customers, regardless of whether the plant operate at a full 671 MW.

C. Depreciation and Plant Retirements in the 2015 Step – Passage of Time (2015 Step) (Issue #10)

1. Background

158. The Company's present application is the first MYRP filed in the state of Minnesota. The Commission provided guidance for MYRPs in its MYRP Order, which, in part, requires that MYRPs be "designed to recover the cost of specific, clearly identified capital projects and, as appropriate, non-capital costs."[281]

159. Consistent with the Commission's MYRP Order, the Company's MYRP "seeks to recover costs related to specific capital projects and a limited number of noncapital expenses associated with capital investments."[282] Specifically, the Company proposed to include in the 2015 Step: a limited number of capital additions; certain capital additions originating in Northern States Power Company-Wisconsin (NSPW); and operations and maintenance items directly tied to these capital additions such as pollution control chemical costs, property taxes, and other minor costs and credits.[283]

160. To develop the proposed revenue requirement for the 2015 Step, the Company utilized the same methodology it uses to calculate revenue requirements for a regular test year, except such calculations were limited to only the 2015 Step capital additions and related O&M. This includes carrying forward "ongoing monthly balances…for the various components of rate base including plant in-service,

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[281] *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multi Year Rate Plans under Minn. Stat. § 216B.16, subd. 19*, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTI YEAR RATE PLANS, Docket No. E,G-999/M-12-587 (June 17, 2013) ("MYRP Order").
[282] Ex. 99, Clark Direct at 10.
[283] Ex. 95, Robinson Direct at 3.

Construction Work In Progress (CWIP), accumulated depreciation provision, and accumulated deferred taxes."[284]

161. During discovery, the Department issued information request No. 2113, which sought to quantify a passage of time adjustment by requesting that the Company provide: "the rate base, income statement and revenue requirement effect of updating depreciation expense and accumulated depreciation reserve to reflect the passage of time for 2015 (except for the 2015 Step projects already reflected in the 2015 Step)."[285]

162. The Company inadvertently responded to this request by summarizing the impact in 2015 of rolling the average depreciation reserve forward one year, while excluding both projects already considered in the 2015 Step and all other 2015 additions to plant-in-service and arrived at an amount of $17.53 million.[286] The Company did not include a rate of return on the annualized rate base effect of the capital projects placed into service in 2014 in this analysis, nor did it include annualization of depreciation expense for all non-Step plant placed into service in 2014.[287]

2. Department's Position

163. Based on the Company's response to information request No. 2113, the Department proposed adjustments to the 2015 revenue requirement to reflect: (1) 2015 capital retirements of transmission and distribution facilities; and (2) accumulated depreciation changes due to the passage of time from 2014 to 2015 for all projects not already incorporated in the Step.[288]

164. The Department stated that the basis for its recommendation was that it would be inequitable to allow the Company to add $68.865 million in plant additions

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[284] Ex. 95, Robinson Direct at 5.
[285] Ex. 430, Campbell Direct at Schedule 32.
[286] Ex. 430, Campbell Direct at Schedule 32; Ex. 94, Perkett Rebuttal at 5-6.
[287] Ex. 94, Perkett Rebuttal at 5-6.
[288] Ex. 429, Campbell Direct at 158.

for the 36 Step year projects and to increase related property taxes, without reflecting reduced depreciation expense and related accumulated depreciation for existing plant in rate base for the passage of time from 2014 to 2015 and without capturing 2015 plant retirements.[289]

165. The Department recommended a $535,552 reduction to the revenue requirements for the 2015 Step to account for forecasted 2015 transmission and distribution plant retirements.[290] The Department recommended a $17.53 million reduction in the revenue requirements for the 2015 Step to account for updates to the depreciation expense and accumulated depreciation reserve for all plant in rate base for 2015.[291]

166. In its initial brief, the Department altered its methodology for calculating a passage of time adjustment such that only changes to accumulated depreciation reserve need to be included. Specifically, "Ms. Campbell determined that it was not necessary to update depreciation [expense] for the passage of time for [the non-2015 Step] capital projects were in service by the end of 2014…."[292] This was because the Company's 2015 Step accounted for the revenue requirements of 81.3 percent of the Company's total increase in 2015 rate base.[293]

3. Company's Position

167. The Company argued that the Department's proposed adjustment is based on an incorrect calculation in response to the Department's information request no. 2113 as the Company's answer only provided the increase in depreciation reserve without providing the offsetting increase in depreciation expense in its response.[294] The Company stated that its error is not a reasonable basis for an adjustment.

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[289] Ex. 429, Campbell Direct at 158.
[290] Ex. 442, Lusti Surrebuttal at 39-40.
[291] Ex. 442, Lusti Surrebuttal at 39-40.
[292] Department Initial Brief at 233.
[293] *See* Department Initial Brief at 233; Ex. 435, Campbell Surrebuttal at p. 119.
[294] *See* Ex. 430, Campbell Direct at Schedule 32 (only providing roll forward of accumulated depreciation reserve).

168. The Company also contended that a passage of time adjustment is neither appropriate nor reasonable. The Company explained that passage of time adjustments may be appropriate in some limited circumstances, such as when additions to rate base outpace the growth of the utility's depreciation expense, but this is not the case in this proceeding. The Company provided evidence that the Company's depreciation expense in 2015 outpaces its additions to rate base and adjusting for the passage of time would increase the Company's 2015 Step request.[295]

169. The Company further stated that a passage of time adjustment would discourage utilities from proposing multi-year rate plans. This is because utilities will be incentivized to: (1) forgo the use of a multi-year rate plan in favor of a traditional rate case in which they can ask for their entire revenue deficiency without the risk of a passage of time adjustment; or (2) request their entire deficiency in every year of a multi-year rate plan, which may be inconsistent with the Commission's objectives expressed in its MYRP Order.[296]

170. The Company also argued that the Department's proposed passage of time adjustment is unbalanced and asymmetrical. The Department's proposal seeks to roll forward depreciation reserve and expense for the entirety of the Company's 2014 rate base but the Company's 2015 Step request is limited to only 36 capital projects.[297] For the passage of time adjustment to be symmetrical, the Company argued that it must include "the actual increase in plant from the same group of projects, which increases rate base… [and] the annualization of depreciation expense for these projects. Any analysis of whether or not a passage of time adjustment should

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[295] Ex. 94, Perkett Rebuttal at 4-7.

[296] *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multi Year Rate Plans under Minn. Stat. § 216B.16, subd. 19*, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTI YEAR RATE PLANS, Docket No. E,G-999/M-12-587 (June 17, 2013) ("MYRP Order").

[297] Ex. 429, Campbell Direct at 162 ("it is not fair to update for 36 new plant additions … and not recognize the net decrease in depreciation, due to the passage of time, for all other plant in rate base"); Ex. 100, Clark Rebuttal at 33-34; Ex. 94, Perkett Rebuttal at 3-7.

be made needs to include the full revenue requirement impacts of the plant that is being annualized."[298]

171. The Company also challenged the Department's calculation of the $17.5 million adjustment as inconsistent with the Department's proposal to carry forward both the depreciation reserve and expense on the entirety of the Company's 2014 rate base. Specifically, the $17.5 million downward adjustment reflects only the rolling forward of the depreciation reserve, and fails to consider the associated $18,478,528 increase in depreciation expense.[299] Netting these two items together would result in the correct passage of time upward adjustment of $949,609.[300]

4. Conclusion

172. The Department's proposed passage of time adjustment should not be adopted as it is inconsistent with the Company's adherence to the Commission's MYRP Order that limited the scope of the Step to specific capital projects. The Department's proposed passage of time adjustment is also contrary to the concept of symmetrical ratemaking. This is because the Department's proposed adjustment expands the scope of the 2015 Step to solely recognize depreciation for non-Step projects.

173. Moreover, when the "passage of time" adjustment is calculated symmetrically to include both accumulated depreciation reserve and depreciation expense, the adjustment would increase the Company's Step revenue requirement by $949,609, rather than decrease it by approximately $17.5 million as proposed by the Department.

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[298] Ex. 94, Perkett Rebuttal at 6.
[299] *See* Ex. 94, Perkett Rebuttal at Schedule 2, page 5 (calculating both the roll forward of depreciation reserve and expenses).
[300] Company Initial Brief at 52.

D. Qualified Pension – Discount Rate (2014) and Market Loss (2014) (Issues # 4 and 5)

1. Introduction and Overview of Pension Expense Calculations

174. Like other utilities, the Company offers its employees not only current cash compensation, but also retirement benefits, including a defined benefit qualified pension plan.[301] The pension benefit (also referred to as the "qualified pension") is part of the Company's overall compensation program.[302]

175. The Company has two pension plans: the pension for the Xcel Energy Service employees (the XES Plan), and the pension plan for NSPM employees (the NSPM Plan).[303]

176. The Company uses two different methods to determine the pension expense (i.e., the accrual for future pension liabilities). For the NSPM Plan, the Company uses the aggregate cost method (ACM), and for the XES Plan, the Company uses the Statement of Financial Accounting Method (FAS) 87 method.[304] Both are actuarially approved methods of calculating, and recovering over the course of an employee's career, the amount of money necessary to satisfy the Company's pension expense to that employee.[305] Both rely on the Company's experience from prior years to determine the current pension expense.[306]

a. ACM Calculation

177. The Company calculates pension expense under the ACM by comparing the market value of the NSPM Plan assets to the present value of future benefits (PVFB).[307] The difference between those amounts, if any, is the unfunded liability,

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[301] Ex. 82, Moeller Direct at 11-12.
[302] Ex. 82, Moeller Direct at 11.
[303] Ex. 82, Moeller Direct at 15.
[304] Ex. 82, Moeller Direct at 15-16.
[305] Ex. 82, Moeller Direct at 16.
[306] Ex. 82, Moeller Direct at 16.
[307] Ex. 82, Moeller Direct at 32-33.

and that unfunded liability must be funded over the future working lives of current employees.[308]

178. "Asset gains" or "asset losses" arise when the actual returns on the NSPM Plan assets are greater or lesser than the expected returns.[309] "Liability gains" or "liability losses" occur when the other components of pension expense differ from expectations.[310]

179. Prior-period asset gains or losses are "phased in" to an amortization pool over a five-year period.[311] They are then amortized over the remaining service lives of the employees.[312] Thus, only a fraction of the prior-period asset gain or loss is incorporated into the qualified pension expense calculation in a given year. For example, although the remaining net unamortized asset losses from 2008 for the NSPM Plan total $95.5 million, only $6.2 million is being included in the test year qualified pension expense as a result not only of the phase-in and amortization, but also of the offsets from other prior-period gains.[313]

b. FAS 87 Calculation

180. The method for calculating qualified pension expense under FAS 87 differs somewhat from the ACM method, but the ultimate goal is the same – "to measure the value of the pension assets today, to compare those values to a future liability, and to inform us as to the unfunded liability that must be funded so that we can meet that future obligation."[314]

181. FAS 87 requires the utility to measure pension expense based on five individual components: service cost, interest cost, expected return on assets (EROA),

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308 Ex. 82, Moeller Direct at 33.
309 Ex. 82, Moeller Direct at 19-20.
310 Ex. 82, Moeller Direct at 20.
311 Ex. 82, Moeller Direct at 22.
312 Ex. 82, Moeller Direct at 26-27.
313 Ex. 82, Moeller Direct at 29-30 and Schedule 5.
314 Ex. 83, Schrubbe Rebuttal at 17; *see also* Ex. 82, Moeller Direct at 16.

prior service cost, and the net gain or loss from prior years.[315] Net asset gain or loss from prior years occurs when EROA in a prior year was different from the actual return in that year.[316]

182. The asset gains or losses are phased in on a five-year schedule, and then they are netted not only with any liability gains or losses from the previous year but also with unamortized gains and losses from prior years; if the resulting cumulative gains and losses are more than 10 percent of the projected benefit obligation (PBO) or of the assets' market value, then the excess amount of those gains and losses is amortized over the average expected remaining years of service of the Company's employees.[317] Thus, analogous to the calculation of asset values under the ACM calculation, the net gain or loss under the FAS 87 includes the netting of many pre-2008 gains, the 2008 Market Loss, and post-2008 gains and losses.[318] That net number, and the four other elements of pension expense identified above, are used to determine the test year qualified pension expense under FAS 87.[319]

c. Discount Rate

183. Under both the ACM method and the FAS 87 method, calculation of the qualified pension expense requires the use of a discount rate.[320] Under the ACM, the discount rate is a longer-term rate and is set to equal the rate of return.[321] FAS 87 uses a discount rate based on a bond-matching approach, which is recalculated each year to most accurately value the liability at a point in time using current period information.[322]

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315 Ex. 82, Moeller Direct at 36.
316 Ex. 82, Moeller Direct at 38; Ex. 83, Schrubbe Rebuttal at 21.
317 Ex. 82, Moeller Direct at 38-39.
318 Ex. 83, Schrubbe Rebuttal at 21.
319 Ex. 82, Moeller Direct, at 36, 41.
320 Ex. 82, Moeller Direct at 41, 75.
321 Ex. 82, Moeller Direct at 42.
322 Ex. 82, Moeller Direct at 42.

2. Summary of Recommendations

184. In the Company's 2013 rate case, the Commission required the Company to provide substantial information in its future rate case filings relating to its qualified pension plans.[323] In this case, the Company provided all of the requested information.[324]

185. The Company provided a very detailed explanation of how its qualified pension expense is calculated for ratemaking purposes.[325] In Direct Testimony, the Company proposed recovery of $19.9 million for qualified pension expense for the test year of 2014.[326]

186. In Rebuttal Testimony, the Company provided updated information on various factors that are part of the calculation of the qualified pension expense, and the Company's final requested recovery for qualified pension expense for the test year was $20.9 million.[327]

187. The Company's requested recovery for qualified pension expense includes recovery for the after-effects of the 2008 Market Loss, consistent with its historical practices of pension accounting.[328] The Company's requested recovery also assumes that the discount rate used for the FAS 87 calculation should be 4.74 percent, which is the updated rate as of December 31, 2013.[329]

188. The only intervenor to provide testimony on qualified pension expense was the Department. The Department and the Company agreed on several assumptions related to the calculation of pension and benefit expense.[330] The

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323 Ex. 82, Moeller Direct at 2-3.
324 Ex. 82, Moeller Direct at 13-14, 20-21, 46-49, 55-64, 104-121, Schedules 2, 5; Ex. 78, Figoli Direct at 2, 70-73; Ex. 84, Wickes Direct at 2, 4-33.
325 Ex. 82, Moeller Direct, *passim*.
326 Ex. 82, Moeller Direct at 9, 12, 49, 74-78.
327 Ex. 83, Schrubbe Rebuttal at 9, 60-61.
328 Ex. 82, Moeller Direct at 44-64; Ex. 83, Schrubbe Rebuttal at 15-29.
329 Ex. 83, Schrubbe Rebuttal at 39-47.
330 Ex. 83, Schrubbe Rebuttal at 2-3. One of the issues on which the Department and Company agreed was the measurement date for the pension calculations (Issue # 18).

Department disagreed with the Company's qualified pension expense calculation as to two issues: (1) the Department recommended that the discount rate for the calculation of pension expense under the FAS 87 method be increased from 4.74 percent to 7.25 percent; and (2) the Department recommended that half of the 2008 Market Loss be eliminated from the calculation of qualified pension expense in the 2014 test year.[331]

3. FAS 87 Discount Rate

189. In Direct Testimony, the Company explained that when it calculated 2014 qualified pension expense, it originally used a discount rate of 4.03 percent in the FAS 87 methodology that is used with the XES Plan.[332]

190. The primary source for the discount rate is a bond-matching study that is performed as of December 31 of each year.[333] The study includes a matching bond for each of the individual projected payout durations within the plan based on projected actuarial experience.[334] The bonds used in the study must meet certain well-established criteria,[335] and the Company employs numerous tests to validate the reasonableness of the discount rate produced by the bond-matching study.[336]

191. The Company has consistently used this bond-matching study approach because it provides the most accurate discount rate available from the alternatives that meet the standards of FAS 87.[337]

192. In Rebuttal Testimony, the Company noted that the 4.03 percent figure was based on information from December 31, 2012, and thus was now outdated.[338] Accordingly, the Company updated its proposed discount rate for use in the XES

[331] Ex. 431, Campbell Direct at 134.
[332] Ex. 82, Moeller Direct at 80.
[333] Ex. 82, Moeller Direct at 82.
[334] Ex. 82, Moeller Direct at 82.
[335] Ex. 82, Moeller Direct at 82.
[336] Ex. 82, Moeller Direct at 82-84.
[337] Ex. 82, Moeller Direct at 83.
[338] Ex. 83, Schrubbe Rebuttal at 8.

Plan pension expense calculation, based on the same methodology but based on information as of December 31, 2013, to 4.74 percent.[339] The Company argued that this rate is reasonable because it is consistent with the discount rate used by utilities and other large companies and because customers have benefitted from the lower interest rates reflected in that discount rate.[340]

193. The Department recommended setting the XES Plan discount rate at 7.25 percent, which is the EROA used in the XES Plan.[341] The Company opposed the Department's recommendations regarding the XES Plan discount rate, for a number of reasons.

194. One of the bases for the Department's argument that the EROA should be used as the discount rate for purposes of calculating FAS 87 pension expense was the Department's belief that use of the EROA was required by the federal Employee Retirement Income Security Act (ERISA); the Department relied on a 2004 document to support this proposition.[342] In response, the Company pointed out that in 2006, ERISA was amended to require the discount rate used for purposes of pension funding to be established using a corporate bond yield curve, not EROA.[343]

195. The Department asserted that in the Company's previous rate case, the Commission approved the method of using the same discount rate and EROA for the XES Plan.[344] The Company responded that the Commission's decision in the prior rate case was limited to the facts of that case.[345] Moreover, in the recent CenterPoint

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339 Ex. 83, Schrubbe Rebuttal at 39.
340 Company Initial Brief at 65-66.
341 Ex. 431, Campbell Direct at 110, 118.
342 Department Initial Brief at 99-100 *citing* "Fundamentals of Current Pension Funding and Accounting for Private Sector Pension Plans."
343 *See* 29 U.S.C. § 1083 (h)(2)(C).
344 Ex. 431, Campbell Direct at 117-18.
345 Ex. 83, Schrubbe Rebuttal at 42.

case, the Commission did not accept the Department's proposal (and the ALJ's recommendation) that the discount rate must match the EROA.[346]

196. The Department also believed that there is no reason to use a discount rate that is lower than the EROA, and that doing so artificially overstates pension expense for ratemaking purposes and is therefore unreasonable.[347] The Company responded that use of a discount rate derived from the bond-matching study, rather than a discount rate identical to the EROA, does not artificially overstate pension expense for ratemaking purposes. Rather, FAS 87 is an accounting standard that specifies standards upon which the discount rate should be based.[348] Use of the EROA as the basis for the discount rate would be inconsistent with FAS 87's requirements, and thus would be a departure from GAAP.[349] The Company urged that the Commission should adhere to GAAP in order to avoid creating a disparity between regulatory books and accounting books – "an artificial divorce between our actual costs and what we recover in rates."[350] The Department argued that rates need not be set according to accounting standards, but the Company noted that the Department provided no persuasive basis to vary from accounting standards in calculating the pension expense.

197. The EROA is an offset to the service cost and the interest cost components of the FAS 87 calculation.[351] The Company noted that its use of an EROA higher than the discount rate actually reduces pension expense: if the discount rate had been equal to the EROA since the inception of the XES Plan, customers would have paid more in pension expense through the years because the service cost

[346] Schrubbe Rebuttal at 42-43 (quoting *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, Docket No. GR-13-316 (June 9, 2014).
[347] Ex. 431, Campbell Direct at 116.
[348] Ex. 83, Schrubbe Rebuttal at 43.
[349] Ex. 83, Schrubbe Rebuttal at 40, 43; Ex. 82, Moeller Direct at 86-87.
[350] Tr. Vol. 2 at 22 (Schrubbe); Ex. 82, Moeller Direct at 89.
[351] Ex. 82, Moeller Direct at 37.

and interest cost elements of the FAS 87 calculation would have been higher.[352] "[R]equiring the use of the EROA to set the discount rate would lead to an artificial liability gain."[353]

198. The Company noted that its customers are benefiting from a higher discount rate relative to other utilities' discount rates. Specifically, approximately 73% of the Company's pension cost is attributable to the NSPM Plan, and the Company uses the EROA as the discount rate for the calculation of pension expense for that plan.[354] In contrast, in the recent CenterPoint case, the Commission approved the use of a five-year average of discount rates to calculate CenterPoint's qualified pension expense, instead of using the EROA. That five-year average was 5.35 percent, although CenterPoint's EROA was 7.25 percent.[355] Thus, the Commission-approved discount rate was 190 basis points lower than the EROA for CenterPoint's entire qualified pension expense balance, whereas the difference between the Company's FAS 87 discount rate and the EROA affects only 27 percent of the Company's qualified pension balance.

199. The Company also stated that the discount rate used by the Company is not "artificially low," as the Department contended.[356] Instead, the discount rate used by the Company is consistent with the discount rates used by utilities and other large companies: a Towers Watson study showed that the average discount rate used for qualified pension expense at December 31, 2013 was 4.87 percent for 151 Towers Watson clients in the Fortune 1000, and the Citigroup benchmark on that date was 4.95 percent.[357]

352 Ex. 82, Moeller Direct at 89.
353 Tr. Vol. 2 at 29 (Schrubbe).
354 Ex. 83, Schrubbe Rebuttal at 45.
355 Ex. 83, Schrubbe Rebuttal at 46.
356 Ex. 429, Campbell Direct at 116.
357 Ex. 83, Schrubbe Rebuttal at 44.

200. The Department further argued that the XES Plan discount rate used by the Company is not independently established.[358] The Company explained that contrary to the Department's assertion, the FAS 87 discount rate is based on independent information: objective bond-yield studies that are validated by reference to third-party benchmarks, such as the Citigroup Benchmark and the Citigroup Above Median Benchmark, and with further confirmation by review of general survey data provided by Towers Watson and the Edison Electric Institute.[359] Moreover, the Company's selection of pension plan assumptions is subject to significant oversight by outside entities and the Company's own auditor.[360]

201. The Department also asserted that the Company's discount rate of 4.74 percent is artificially low compared to the EROA of 7.25 percent because it relies on a point-in-time measurement.[361] Although the bond-matching study is made at a point in time, it reflects long-term yields for bonds over the entire expected payout range of the pension plan.[362] Accordingly, the Company stated that the discount rate derived from this methodology reflects the market's current best estimate of future bond yields.[363]

202. The Company's proposed calculation of the FAS 87 discount rate closely reflects market interest rates.[364] Rates commensurate with current levels have been in effect for more than half a decade.[365] The discount rate used in the Company's calculation of FAS 87 pension expense is based on actual bond rates, and customers are benefiting from those bond rates through reduced borrowing costs.[366] Most

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358 Ex. 431, Campbell Direct at 113.
359 Ex. 83, Schrubbe Rebuttal at 7.
360 Ex. 85, Wickes Rebuttal at 3-7; Ex. 83, Schrubbe Rebuttal at 8.
361 Ex. 431, Campbell Direct at 116.
362 Ex. 82, Moeller Direct at 86.
363 Ex. 82, Moeller Direct at 86.
364 Ex. 31, Tyson Rebuttal at 21.
365 Ex. 83, Schrubbe Rebuttal at 45; Ex. 31, Tyson Rebuttal at 22; Tr. Vol. 5 at 70 (Campbell) (admitting that 10-year treasury bill rates have not exceeded 7 percent since 2000).
366 Ex. 83, Schrubbe Rebuttal at 45.

recently in May 2014, NSPM issued $300 million of 30-year first mortgage bonds at a rate of 4.125 percent, and customers will benefit from that favorable cost of debt over the entire lives of the bonds.[367]

203. The Company argued that the Department's proposed 7.25 percent discount rate is not representative of current rates as it is higher than any ten-year treasury rate in the last decade.[368] The Company argued that it would be contrary to sound ratemaking principles to give customers the benefit of low bond rates where debt rates are concerned but to substitute a higher rate for purposes of calculating qualified pension expense.[369] As a result, it would be highly inconsistent for the Company's actual low costs of short-term debt and long-term debt to be used to determine its overall ROR and cost of service while the low interest rate environment that supports those low actual costs of short-term debt and long-term debt is not reflected in the Company's pension expense calculation.[370]

4. 2008 Market Loss

204. The Company provided an exhaustive description of how prior years' gains and losses are accounted for in the calculation of pension expense.[371] The Company recognized that the treatment of the 2008 Market Loss was disputed in the prior rate case, and provided detailed information relating to questions and issues from that case, to clarify its position and minimize confusion.[372] It further provided a thorough explanation of why the 2008 Market Loss should be included in the pension expense for this case.[373]

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[367] Ex. 83, Schrubbe Rebuttal at 45; *see also* Ex. 82, Moeller Direct at 10.
[368] Ex. 31, Tyson Rebuttal at 3, Schedule 1.
[369] Ex. 83, Schrubbe Rebuttal at 45; Ex. 82, Moeller Direct at 11.
[370] Ex. 31, Tyson Rebuttal at 22-23.
[371] Ex. 82, Moeller Direct at 18-32.
[372] Ex. 82, Moeller Direct at 44-49.
[373] Ex. 82, Moeller Direct at 55-64.

a. The Company's Position

205. The Company outlined several reasons why qualified pension expense, including the effects of the 2008 Market Loss, should be included in rates.

206. First, the Company notes that both the Company and the Department agree that retirement benefits are a legitimate cost of service, and that the Company should be allowed to recover the reasonable costs attributable to those retirement benefits.[374]

207. Second, the Company pointed out that for decades the Company has been using a symmetrical method of including both gains and losses from prior years in its qualified pension expense.[375] For many years the Company had significant gains because of its pension plan investment strategy, and customers reaped the benefits through market gains that exceeded the EROA.[376] Because the customers received the benefits in the high-return years before 2008 (as well as after due to phase-in of losses), and because customers have received the benefit of high-return years since 2008, it is reasonable to include the effects of prior years' gain and loss experience in current pension expense.[377]

208. Third, the Company noted that the Company's consistent practice of symmetrically including both gains and losses has provided customers with very substantial benefits over time.[378] From 2000 to 2014, the cumulative benefit to customers has been approximately $332 million on a Minnesota jurisdictional basis.[379] From 2000 to 2011, the qualified pension expense was at or below zero because of asset gains or liability gains.[380] Thus, the Company stated that it would be neither equitable nor reasonable for the Company to pass along all gains to customers while

[374] Ex. 82, Moeller Direct at 56; Ex. 431, Campbell Direct at 99.
[375] Ex. 82, Moeller Direct at 56-57.
[376] Ex. 82, Moeller Direct at 57.
[377] Ex. 82, Moeller Direct at 57-58.
[378] Ex. 82, Moeller Direct at 56, 58-61.
[379] Ex. 82, Moeller Direct at 60.
[380] Ex. 82, Moeller Direct at 60.

absorbing all losses.[381] Even in 2009 and 2010, prior-period gains from years before 2008 offset the portions of the 2008 Market Loss that were being phased-in and amortized under the ACM and FAS 87 approaches.[382] Only in 2011 did the phased-in and amortized portions of the 2008 Market Loss grow large enough that they could not be completely offset by the prior period gains, but even then the pension expense was lower than it would have been without the offsets of prior-period gains.[383]

209. Fourth, the Company argued that shareholders and employees receive no benefit from gains on pension assets – federal law prohibits the withdrawal of money from a qualified pension trust fund except to pay earned benefits.[384] Rather, the gain benefits customers because it reduces the pension expense in the Company's revenue requirement.[385]

210. Finally, the Company stated that the Company's calculation of qualified pension expense is consistent with "normal ratemaking."[386] The Company argued that if the Commission disallowed recovery of the 2008 Market Loss as the Department has requested, that would create regulatory uncertainty and might require the Company to report a financial impairment (*i.e.*, a reduction in the net of the unrecognized gains and losses) that could have a dramatic effect on the Company's earnings.[387]

211. For these reasons, the Company asked the Commission to authorize recovery of an amount of pension expense that will incorporate the phased-in and amortized portions of the 2008 Market Loss, consistent with its historical practice.[388] $12.0 million of the Company's total 2014 test year qualified pension expense is

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381 Ex. 82, Moeller Direct at 61.
382 Ex. 82, Moeller Direct at 6.
383 Ex. 82, Moeller Direct at 61.
384 Ex. 82, Moeller Direct at 62.
385 Ex. 82, Moeller Direct at 62.
386 Ex. 83, Schrubbe Rebuttal at 24.
387 Ex. 82, Moeller Direct at 63.
388 Ex. 82, Moeller Direct at 62.

associated with the 2008 Market Loss ($8.5 million from the NSPM Plan and $3.5 million from the XES Plan).[389]

b. The Department's Position

212. The Department opposed the inclusion of the 2008 Market Loss component of the pension expense.[390] The Department stated that the 2008 Market Loss is $12.1 million, but the Company noted that this number does not include any of the asset gains or losses since 2008; when those are considered, the asset loss used in calculation of test year pension expense is $9.6 million.[391]

213. The Department's position concerning the Market Loss, as asserted in its Direct Testimony, was that it would be more "reasonable" for ratepayers to "pay for 50 percent" of the 2008 Market Loss.[392] The basis for the Department's recommendation was to make the Company's pension expense more "fair."[393]

214. The Department's assertions were based in part on the assumption that the Company compares the value of the pension plan assets to the future liabilities, takes the difference, and then adds the 2008 Market Loss to that difference and amortizes the sum of the two amounts.[394] The Company mathematically demonstrated that it did not make any such separate adjustment for the 2008 Market Loss.[395] The Department recognized this in Surrebuttal Testimony.[396]

215. The Department's position was also based on the belief that "the Company's accounting for FAS 87…leads Xcel to continue to propose an extra adjustment to current rates for the 2008 market loss."[397] In response, the Company countered that it only uses the FAS 87 approach for calculation of the pension

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389 Ex. 82, Moeller Direct at 49, 53.
390 Ex. 431, Campbell Direct at 134-135.
391 Ex. 82, Moeller Direct, Schedule 5 at 1.
392 Ex. 431, Campbell Direct at 134-135.
393 Ex. 431, Campbell Direct at 135.
394 Ex. 431, Campbell Direct at 129.
395 Ex. 83, Schrubbe Rebuttal at 19-22; Ex. 85, Wickes Rebuttal at 9-11.
396 Ex. 437, Campbell Surrebuttal at 78, 92.
397 Ex. 431, Campbell Direct at 129.

expense for the XES Plan.[398] The Company uses the ACM approach for calculation of the pension expense for the NSPM Plan, which accounts for about 73% of the Company's pension expense.[399] And, as described above, there is no "extra adjustment."[400]

216. In surrebuttal, the Department presented several new arguments against inclusion of the 2008 Market Loss, and continued to recommend that only 50 percent of the 2008 Market Loss be included in the pension expense.[401]

217. The Department expressed concern about the Company's "generosity to its employees," and asserted that "requiring ratepayers to pay for all pension expenses is especially troubling in light of the additional 401K plan…."[402]

218. The Company countered that to retain important and skilled personnel, as well as to hire new employees, the Company must provide a competitive level of benefits.[403] The Company noted that its employee benefits programs are in line with its peers, and its benefits for new employees are lower than most of its peers.[404] To ensure that its retirement benefits strike a fair balance between the interests of employees and the Company's customers, the Company has made several design changes over the last decade that reduced the qualified pension benefit levels for new employees.[405] As a result of those changes, the retirement program that the Company offers to new hires ranks in the lowest quartile when compared to those of peer utility companies.[406] As required by the Commission in the previous rate case, the Company has explored freezing or amending prior pension benefits, but the Company has concluded that doing so would create risks, including the risk that skilled retirement-

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398 Ex. 83, Schrubbe Rebuttal at 23.
399 Ex. 83, Schrubbe Rebuttal at 23.
400 Ex. 83, Schrubbe Rebuttal at 23.
401 Ex. 436, Campbell Surrebuttal at 89-95.
402 Ex. 436, Campbell Surrebuttal at 91.
403 Ex. 78, Figoli Direct at 4-15.
404 Ex. 82, Moeller Direct at 56; Ex. 78, Figoli Direct at 67-70.
405 Ex. 82, Moeller Direct at 101; Ex. 78, Figoli Direct at 68-69.
406 Ex. 78, Figoli Direct at 24.

age employees would leave.[407] The five percent Cash Balance program, which is the defined benefit retirement program available to newly hired employees, provides only an 8 percent income replacement level, incommensurate with the Department's proposed 50 percent adjustment.[408]

219. The Department also expressed concern that the Company included over 60 percent of the 2008 Market Loss in the 2014 pension expense, suggesting that "the Company may not have reasonably managed its pension assets."[409]

220. The Company pointed out that the Company's pension trust portfolio is highly diversified with holdings in, among other things, U.S. and international public equities; private equity, real estate and commodities positions; and fixed income securities.[410] The Company stated that it holds a diversified portfolio because it needs to: (1) balance the opportunity for financial market growth, which can result in improving our pension funding status, with its obligations to maintain minimum funding requirements established by law; (2) pay monthly cash benefits to retirees; and (3) sustain its fiduciary duty to the beneficiaries, namely our union and non-union employees, of our pension trust.[411] Individual investors who do not have these obligations, or who do not have current cash flow funding requirements from their portfolios, may try to obtain better returns in a given year, but that usually means accepting greater financial market risk than the Company can accept.[412] Nevertheless, each asset class in the Company's pension trust performed consistent with market returns last year, including the Company's U.S. equities position, which earned 33.3

[407] Ex. 78, Figoli Direct at 70-72.
[408] Ex. 82, Moeller Direct at 70-71, 80.
[409] Ex. 436, Campbell Surrebuttal at 93.
[410] Ex. 116, Tyson Opening Statement at 2.
[411] Ex. 31, Tyson Rebuttal at 17; Ex. 116, Tyson Opening Statement at 3.
[412] Ex. 116, Tyson Opening Statement at 3.

percent.[413] This demonstrates that the Company's management of its pension trust is prudent and reasonable.[414]

221. The Department's assertions were also based in part on the assumption that "the turnaround time for full recovery is estimated to be just a few years in the future," suggesting that the Company's qualified pension expense will be zero in a few years.[415] The Company pointed out that contrary to the Department's assumptions, there will continue to be pension expense for the next few years, because the Company has contributed substantially more than it has recognized in pension expense since the 2008 market collapse.[416]

222. The essence of the Department's opposition to the inclusion of the entirety of the 2008 Market Loss in the Company's pension expense continued to be that the Department considered the Company's position to be "unreasonable."[417] The Company recognized that the magnitude of the 2008 Market Loss makes it seem as if the Company has changed its accounting and ratemaking practices, but explained that the opposite is true: the proposed $12.0 million for 2008 Market Loss in the Company's calculated pension expense is the result of consistently applying the ACM and FAS 87 pension accounting methods.[418]

> "Even though our pension expense did increase, this is not due to any changes in how we calculate our pension obligations nor manage our pension trust. Rather, we have used the same Commission-approved accounting methodologies to determine our pension expense each and every year, both before the 2008 market loss and after. The test year merely represents the current product of the same

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413 Ex. 116, Tyson Opening Statement at 2.
414 Ex. 116, Tyson Opening Statement at 3.
415 Ex. 431, Campbell Direct at 133.
416 Ex. 83, Schrubbe Rebuttal at 26-27.
417 Ex. 436, Campbell Surrebuttal at 94.
418 Ex. 83, Schrubbe Rebuttal at 28.

> formula and is representative of what our actual expense will be in 2014."[419]

223. Accordingly, the Company has shown that its proposed inclusion of 2008 Market Loss in its pension expense is amply reasonable.

5. Alternative Proposals

224. To provide a mechanism that will "normalize" the Company's qualified pension expense, and therefore provide greater predictability and certainty, the Company proposed alternative approaches to determination of the pension expense.[420]

225. First, the Company noted that in its prior rate case, it had proposed to cap the XES Plan expense at the 2011 levels, and to extend the amortization period for prior-period gains and losses from 10 years to 20 years for the NSPM Plan.[421]

226. The Company offered two additional proposals to further moderate the rate offset of the 2008 Market Loss.[422]

227. The first proposal compares a five-year average, normalized qualified pension expense to the Company's actual qualified pension expense each year, with the difference being deferred each year until the normalized amount is revisited in 2017 or 2018, at which time the deferred amount will be amortized over a period of time approved by the Commission.[423]

228. The second proposal would also use the five-year average from 2014 through 2018, which is $18,246,925, but instead of deferring the difference between the Company's actual pension expense and the normalized expense, the Company would defer the difference between the normalized amount and the lesser of the actual qualified pension expense amount each year, or the currently forecasted

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[419] Ex. 126, Schrubbe Opening Statement at 1.
[420] Ex. 83, Schrubbe Rebuttal at 30.
[421] Ex. 83, Schrubbe Rebuttal at 31.
[422] Ex. 83, Schrubbe Rebuttal at 31.
[423] Ex. 83, Schrubbe Rebuttal at 31-34.

expenses for each year during this time period (i.e., 2014-2018).[424] In both alternatives, the Company would provide annual compliance filings.[425]

229. The Company explained that these alternative proposals result in a reduction that is equal to or greater than the reduction proposed by the Department with regard to the discount rate for the FAS 87 pension expense.[426] If the Commission is inclined to adopt some mechanism to moderate the qualified pension expense, the Company recommended that the Commission should adopt one of these alternative proposals instead of changing the discount rate for the XES Plan, which would create an artificial liability gain and depart from GAAP accounting.[427]

230. The Department opposed both of the Company's proposed mechanisms to moderate pension expense, but it found the second one to be "least objectionable."[428] The Department will support the Company's second alternative normalization proposal, with four additional modification recommendations.[429]

231. The Department first requests that the Company not be allowed to earn a return on any deferred amounts. The Department contends that the Company "already receives a return on the prepaid pension asset" and that allowing the Company to earn a return would provide "an inappropriate incentive to make poor investment choices for pension assets."[430]

232. The Company opposed this first modification noting that the prepaid pension asset consists of amounts in the pension trust fund that have not yet been recognized as expense.[431] The Company properly receives a return on those amounts because shareholders have essentially paid the pension expense before it is due, either

[424] Ex. 83, Schrubbe Rebuttal at 34-38.
[425] Ex. 83, Schrubbe Rebuttal at 32, 35.
[426] Ex. 83, Schrubbe Rebuttal at 38-39.
[427] Ex. 83, Schrubbe Rebuttal at 39.
[428] Department Initial Brief at 115.
[429] Ex. 435, Campbell Surrebuttal at 101-102; Ex. 450, Campbell Opening Statement at 7-8.
[430] Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).
[431] Ex. 82, Moeller Direct at 122.

through contributions or asset returns that cannot be removed from the trust. In contrast, the deferred amount that would accrue under the Company's second mitigation mechanism consists of pension expense that *has* come due, but has not been paid by customers. Thus, it too is being funded by shareholders, and those shareholders should earn a return on that amount in addition to the return on the prepaid pension asset.

233. The Company also countered the Department's contention that the Company would have incentive to make poor investment decisions but pointing out that the Company's proposal allows recovery of the *lesser of* actual pension expense or currently forecasted amounts.[432] If the Company changed its allocation to drive up actual expense, it would still be capped at the forecasted amount. Thus, the Company has no incentive to make poor investment decisions.

234. The Department's second proposed modification is that the "overall normalization proposal from the last rate case should impact the new alternative normalization proposals," such that "the $1,054,357 deferral for 2013 XES cap that the Commission decided in Xcel's 2012 rate case should be allowed continued deferral."[433] The Company proposed that feature as part of its rebuttal testimony.[434]

235. The Department's third proposed modification is that the Company "be required to make a case for why the Company should be allowed to amortize any unfunded balances in the future."[435] The deferred amounts will consist of the Company's actual pension expense, which the Department admits is a legitimate cost of service. The Company opposed this modification because the deferral is for the benefit of customers, not the Company, there is no reason to require the Company to bear the burden of proving its right to recover the deferred amounts in future cases.

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432 Ex. 83, Schrubbe Rebuttal at 35.
433 Department Initial Brief at 116.
434 Ex. 83, Schrubbe Rebuttal at 37 ("[A]kin to our first proposal, we believe it would be reasonable to continue deferring the XES Plan cap amounts until the normalization period ends.").
435 Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).

236. The Department's fourth proposed modification is that the Company be required to calculate the allowed pension expense in each year using a discount rate equal to the EROA.[436] The Company opposed this modification for the same reasons set forth above.

6. Recommendations for the Next Rate Case

237. The Department recommended that the Commission require the Company, in its next rate case, to address the reasonableness of the Company's target asset allocation for the pension fund, including ages of retirees and employees.

238. The Company accepted this recommendation.[437] The Company will also provide information addressing its investment strategies and target asset allocations since 2007.[438]

E. Retiree Medical Expenses (FAS 106) – Discount Rate and 2008 Market Loss (2014) (Issues #6 and #19)

239. The Company requested recovery of $4.10 million in test year O&M expenses, and $1.16 million in test year capital costs related to post-retirement medical expenses, under FAS 106 for certain employees who retired prior to 2000.[439] The post-retirement medical benefits provided under FAS 106 are paid to retired employees for health care costs such as medical, dental, vision, and life insurance.[440]

240. The Company accounts for its post-retirement medical benefits under FAS 106 as follows: "The components and calculations of FAS 106 are identical to FAS 87, with one exception. Unlike FAS 87, FAS 106 asset gains or losses are not phased in before they are amortized, but instead the total gain or loss amount is simply amortized over the average years to retirement for active employees. But

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[436] Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).
[437] Ex. 116, Tyson Opening Statement at 2.
[438] Ex. 116, Tyson Opening Statement at 2.
[439] Ex. 81, Moeller Direct at 115.
[440] Ex. 423, Byrne Direct at 37.

otherwise, the FAS 106 benefits are calculated based on assumptions regarding the discount rate, the [expected return on assets], and the salary or wage levels."[441]

241. The Company used four assumptions to calculate its FAS 106 test-year O&M expense: (1) an expected rate of return (EROA) of 7.25 percent for the bargaining employee plan, and an EROA of 6.25 percent for the non-bargaining employee plan; and (2) a measurement date of December 31, 2012; (3) inclusion of 2008 market losses; and (4) a discount rate of 4.08 percent.[442]

1. Expected Rates of Return

242. The Department agreed that the Company's two proposed EROAs of 7.25 and 6.25 percent were reasonable.[443]

2. FAS 106 – Measurement Date Update (2014)

243. The Company and the Department agreed to update the measurement date for FAS 106 to December 31, 2013.[444]

244. This results in a decrease of $666,522 (both O&M and capital) in the test year revenue requirements.[445]

3. 2008 Market Loss

245. The Department recommended that the Commission reduce FAS 106 expenses by $88,500 to reflect a disallowance of half the 2008 Market Loss.[446] The Department explained that its reason for this recommendation was to treat the 2008 market loss costs for FAS 106 consistent with the treatment of 2008 Market Loss for the qualified pension.[447]

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441 Ex. 423, Byrne Direct at 37-38 citing Ex. 81, Moeller Direct at 114.
442 Ex. 81, Moeller Direct at 115; Ex. 423, Byrne Direct at 41.
443 Ex. 423, Byrne Direct 39; Department Initial Brief at 56.
444 Ex. 83, Schrubbe Rebuttal at 8-11.
445 Ex. 90, Heuer Rebuttal at 22.
446 Ex. 423, Byrne Direct at 29.
447 Ex. 423, Byrne Direct at 41.

246. The Company did not agree with the Department's proposed disallowance for the 2008 market loss for FAS 106 for the same reasons it opposed the Department's disallowance for the 2008 Market Loss for qualified pension.[448]

247. The Company's proposed inclusion of the 2008 Market Loss in its FAS 106 is reasonable and consistent with the Company's practice of including both market gains and losses in its calculation of this expense.

4. Discount Rate

248. The Department recommended that the discount rate for FAS 106 should match the respective EROA percentages, consistent with the Department's recommendation for qualified pension expense.[449] The Department's recommendation proposed a discount rate of 7.25 percent for the bargaining employees' plan and a rate of 6.25 percent for the non-bargaining employees' plan, for a weighted average discount rate of 7.11 percent.[450]

249. The Department recommended that the FAS 106 discount rate be increased for the same reasons it recommended increasing the FAS 87 discount rate.[451]

250. The Company disagreed with the Department's recommendation related to the FAS 106 discount rate for the same reasons it opposed the Department's recommendation for the qualified pension discount rate.[452]

251. As the Department's proposal to increase the discount rate is inappropriate for the reasons set forth above related to the FAS 87 discount rate, the Commission should decline to adopt the Department's recommendation.

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448 Ex. 83, Schrubbe Rebuttal at 29.
449 Ex. 423, Byrne Direct at 42.
450 Ex. 423, Byrne Direct at 42.
451 *See* Tr. Vol. 5 at 13 (Byrne).
452 Ex. 83, Schrubbe Rebuttal at 47.

F. Paid Leave / Total Labor (2014) (Issue #7)

252. In its initial filing, the Company requested recovery of $49.906 million in paid leave costs.

253. The Department initially proposed an adjustment to the Company's test year to address a claimed historic over recovery of paid leave costs.[453] In response, the Company explained its paid leave costs are a component of total labor costs, and even if all budgeted amounts for paid leave were not utilized by the Company's employees, the Company still incurred equivalent costs as part of its total labor expenditures.[454] Thus, on an overall basis, the Company's total labor costs were representative of its cost of service.

254. Upon this showing, the Department withdrew its proposed paid leave adjustment;[455] but, then proposed an overall adjustment to the Company's total labor costs of $5.6 million on a Minnesota jurisdictional basis. The Department's proposed total labor adjustment was based on a historical trending of the Company's 2012 actual labor costs and a statement that total labor increases must be capped at three percent per year.[456]

255. Specifically, the Department concluded that by looking at 2011 to 2012 actuals, the total labor cost increase was three percent and that 2013 was an unusual year for labor costs.[457] The Department stated that the Company's 2013 actual labor costs were abnormally high due to nuclear plant outages and the unusually high number of storms.[458] The Department then calculated 2014 total labor costs by increasing 2012 actuals by three percent to calculate a "normalized" 2013 total labor cost. The Department then increased this "normalized" 2013 total labor cost by three

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[453] Ex. 429, Campbell Direct at 95-98.
[454] Ex. 87, Stitt Rebuttal at 3-9.
[455] Ex. 435 Campbell Surrebuttal at 74; Tr. Vol. 5 at 33 (Campbell).
[456] Ex. 435, Campbell Surrebuttal at 72-74.
[457] Ex. 435, Campbell Surrebuttal at 72-73.
[458] Ex. 435, Campbell Surrebuttal at 72.

percent to determine 2014 total labor costs. The Department utilized a three percent growth factor because Department witness Nancy Campbell stated that "an increase of 2 to 3 percent over the costs of a normal year is generally a reasonable increase for labor."[459] The Department's proposed adjustment reflects the difference between the Company's requested 2014 total labor costs and the Department's calculated 2014 total labor costs.[460]

256. The Company stated that the drivers of the Company's labor costs above the Department's proposed three percent cap are due to increases in total labor costs of the Company's Nuclear and Business Systems Business units.[461]

257. With respect to labor costs for the Nuclear Business area, Company witness Mr. O'Connor testified:

> These cost increases have been primarily driven by the cost increases for our internal labor for three following reasons: (1) was have added employees to meet regulatory and safety requirements, (2) we have increased compensation in order to attract and retain in-house expertise, and (3) we have increased our overall headcount in order to drive the performance excellence that will allow for long-term efficiency and sustainability.[462]

258. Mr. O'Connor's testimony provided a detailed explanation supporting the need for these increased labor costs for 2014.[463]

259. With respect to Business Systems labor costs, Company witness Mr. David C. Harkness identified the need for the increased labor spend within the Business Systems Business Area, identifying increases in headcount[464] and an increase

[459] Ex. 435, Campbell Surrebuttal at 72-73.
[460] Ex. 435, Campbell Surrebuttal at 73-74.
[461] Ex. 129, Stitt Opening Statement at 2; Tr. Vol. 2 at 38– 39 (Stitt).
[462] Ex. 51, O'Connor Direct at 83.
[463] Ex. 51, O'Connor Direct at 83-90.
[464] Ex. 62, Harkness Direct at 76.

in contract labor for a variety of support needs.[465] Mr. Harkness also provided considerable support and justification for these increases.[466]

260. Company witness Ms. Amy L. Stitt concluded that "[w]hen taken together, our uncontested increases in Nuclear and Business Systems total labor costs account for virtually all of the Department's proposed total labor cost adjustment. Consequently, the Company has accounted for, and justified, its overall total labor costs and the Department's proposed adjustment should be rejected."[467]

261. The Company also disagreed with the Department's proposed adjustment because it will deny the Company recovery of its representative labor costs.[468]

262. The Company stated that, consistent with the test year concept, the Company has forecasted its cost of service for the 2014 test year and has proposed a total labor budget reflecting this cost of service.

263. The Company also pointed out that there is no discernible overall trend in the Company's total labor costs; rather, different activities in a particular year drive certain increases or decreases in labor costs.[469] The Company further stated that the Department's own analysis indicates that that the Company's total labor costs increased three percent from 2011 to 2012 and then increased approximately 12 percent from 2012 to 2013 and are expected to decrease approximately four percent from 2013 to 2014.[470] Therefore, the Company argued that the total labor costs in the

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465 Ex. 62, Harkness Direct at 78.
466 Ex. 62 Harkness Direct at 76.
467 Ex. 129, Stitt Opening Statement at 2.
468 Company Initial Brief at 71.
469 Ex. 87, Stitt Rebuttal at 6-7 (discussing the drivers of the different total labor costs for the different years presented).
470 Ex. 435, Campbell Surrebuttal at 72.

2014 test year should be judged on the merits of the forecasted cost of service during the test year, rather than historical comparisons suggested by the Department.[471]

264. As the Company has demonstrated that its total labor costs for the 2014 test year is representative and reasonable, the Department's proposed adjustment should not be adopted.

III. OTHER DISPUTED REVENUE REQUIREMENT ISSUES

A. Prairie Island Cancelled EPU Project (2014) (Issue #3)[472]

1. Background

265. The Prairie Island EPU project was proposed by the Company to meet growing energy needs forecasted over the course of several resource plans.[473] The Prairie Island EPU Project sought to increase the capacity of the Company's two Prairie Island nuclear generation units by 164 MW to meet this growing demand.[474] The Company sought Certificate of Need approval from the Commission for the EPU project and this approval was granted in December 2009.[475]

266. The Company undertook Prairie Island EPU Project activities based on this need and the projected benefits of the project.[476]

267. On March 30, 2012, the Company filed with the Commission a Notice of Changed Circumstances proposing to delay the implementation date and to reduce the capacity of the uprate to 135 MW.[477] The Notice of Changed Circumstances was

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[471] *See, e.g. Petition of Interstate Power Company, 416 N.W.2d 800, 810 (1987) (citing* Minn. Stat. § 216B.16, subd. 6 for the proposition that "only costs which are reasonable may receive rate base treatment") (affirming ALJ rejection of certain expenses as historic and outside of the test year).

[472] The issue of AFUDC related to the Prairie Island EPU Project is addressed Section III(B).

[473] Ex. 48, Alders Direct at 7-9; *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, INITIAL FILING, Docket No. E002/CN-08-509 (May 16, 2008).

[474] Ex. 49, McCall Direct at 10.

[475] Ex. 48, Alders Direct at 9.

[476] Ex. 49, McCall Direct at 40.

[477] Ex. 48, Alders Direct at 17-18.

based on changes to the federal licensing process, construction risk, the slower pace of projected economic growth, and decreasing natural gas prices.[478]

268. After receiving Commission approval for the uprate Certificate of Need in late 2009, the Company applied for approval from the NRC to begin using new fuel and fuel assemblies prior to uprate project work.[479] After receiving NRC approval and installing the new fuel, the Company assessed the likely future refueling schedule if the Prairie Island EPU Project was cancelled.[480] The Company determined that without the Prairie Island EPU Project, the installation of new fuel assemblies allowed the Company to extend periods between outages by six-month to twenty four-month cycles for each unit.[481] This eliminated two refueling outages for each unit over the remaining life of the plant, at an estimated customer savings of $75 million on a present value basis.[482] The Company's analysis indicated that the total benefits of the uprate declined to $10 million net present value of revenue requirement (PVRR) compared to the $50 million estimated in the Notice of Changed Circumstance.[483]

269. In response to the Notice of Changed Circumstance, the Department stated that preliminary results showed the Prairie Island EPU Project was cost-effective despite delays in timing and updated assumptions.[484]

270. The Company submitted a supplemental set of comments to the Commission on October 22, 2012.[485] The Company informed the Commission of its evolving analysis and its conclusion that the outstanding risks of delay and increased

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478 Ex. 48, Alders Direct at 18.
479 Ex. 48, Alders Direct at 19.
480 Ex. 48, Alders Direct at 20.
481 Ex. 48, Alders Direct at 20.
482 Ex. 48, Alders Direct at 20.
483 Ex. 48, Alders Direct at 20.
484 *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, DEPARTMENT INITIAL COMMENTS, Docket No. E002/CN-08-509 (May 30, 2012).
485 Ex. 48, Alders Direct at 20.

cost outweighed the small benefit calculation remaining, and rendering further investment in the Prairie Island EPU Project, beyond the investments incurred to date, imprudent.[486]

271. On November 7, 2012, the Commission issued an Order to Show Cause, asking interested persons to present arguments as to why the Commission should not terminate the Certificate of Need for the Prairie Island EPU Project.[487]

272. On December 20, 2012, the Commission voted to terminate the Certificate of Need for the Prairie Island EPU Project prospectively.[488] In its February 2013 Order, the Commission concluded that it was in the public interest to discontinue the Project and that no party had shown cause to continue the Project.[489]

273. In the 2013 rate case, there was discussion and testimony as to whether Prairie Island EPU Project cost recovery should have been sought in the course of that rate proceeding.[490] Ultimately, the Commission's 2013 Rate Case Order determined that the matter was not yet ripe for decision and required that "[i]n the initial filing in its next rate case, Xcel shall provide a complete justification for any rate recovery or deferral of its Prairie Island extended power uprate costs."[491]

274. The Company's initial filing in this proceeding included the required justification of rate recovery.[492]

275. In the initial filing in the current proceeding the Company sought recovery of $66.1 million for the Prairie Island EPU Project, which is the total amount of the expenditures to carry out the Prairie Island EPU Project, plus accrued

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486 Ex. 48, Alders Direct at 20.
487 *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY at 1, Docket No. E002/CN-08-509 (Feb. 27, 2013).
488 *Id.* at 4.
489 *Id.*
490 ALJ REPORT IN 2013 RATE CASE at 86-91.
491 2013 RATE CASE ORDER at Order Point 51.
492 Ex. 99, Clark Direct; Ex. 100, Clark Rebuttal; Ex. 49, McCall Direct; Ex. 48, Alders Direct; Ex. 45, Weatherby Direct; Ex. 47, Weatherby Rebuttal.

AFUDC of $12.8 million.[493] The Company proposed to amortize cost recovery over 12 years while earning a return on the asset, or six years if no return is permitted.[494]

276. Several Parties (the Department, MCC, ICI Group, and OAG) recommended that any recoverable costs should be amortized over a longer period – most commonly over the remaining life of the facility (approximately 20 years) with no return on the asset.[495] In Surrebuttal Testimony and at hearing, the Company and the Department each testified that recovery of Prairie Island EPU Project costs over the remaining life of the facility with a debt-only return of 2.42 percent would be acceptable.[496]

277. The OAG suggested that the Company should be precluded from recovering $10.1 million in Prairie Island EPU Project costs, any return on the costs, and any AFUDC because (i) the Company took a pretax charge of $10.1 million in late 2012 to reflect the uncertainty of earning a return on the asset; and (ii) the Company may have been able to avoid some level of Prairie Island EPU Project costs by cancelling earlier or providing the Commission with earlier updates about evolving circumstances.[497]

278. The ICI group suggested that the Company should not recover any portion of Project costs because the Prairie Island EPU was never "used and useful."[498]

2. Cost Recovery Standard

279. The Commission has addressed several cancelled and abandoned projects in recent years, and has established a clear standard for recovery of cancelled project costs. In particular, the Commission "has consistently treated the issue of

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493 Ex. 99, Clark Direct at 31.
494 Ex. 99, Clark Direct at 31.
495 Ex. 437, Lusti Direct at 12-18; Ex. 340, Schedin Direct at 10-11; Ex. 250, Glahn Direct at 10-12.
496 Ex. 134, Clark Opening Statement at 1; Ex. 373, Lusti Surrebuttal at 17-24
497 Ex. 370, Lindell Direct at 35-44.
498 Ex. 250, Glahn Direct at 10-12.

abandoned plant costs as turning on the unique facts and circumstances surrounding each rate case and each plant."[499] The Commission has determined that the appropriate test for cost recovery is whether the costs were "prudently incurred in good-faith" not the "used and useful" test recommended by ICI:

> The Commission concludes that there is no public interest or regulatory benefit to be gained by disallowing costs prudently incurred in good-faith to meet future need. And there is much to be lost by potentially chilling a utility's diligence in developing resources and in promptly withdrawing from projects when experience shows that they will no longer serve ratepayers' best interests.[500]

280. The "prudently incurred in good faith" standard is the correct standard to apply to a cancelled project because if a "used and useful" test were applied, no project that was cancelled before it was placed in service could be eligible for cost recovery.[501]

281. The ICI Group's adjustment relies on the "used and useful" standard as opposed to the correct "prudently incurred in good faith" and therefore, the proposed adjustment should not be adopted.

3. Cost Recovery for Prairie Island EPU Project Costs

282. First, the OAG argued that cost recovery for the Prairie Island EPU Project costs is barred in this rate proceeding because the Company sought neither cost recovery nor deferred accounting in its previous rate case.[502]

283. The Company noted that this issue was addressed in the Company's previous rate case, and the Commission concluded that the Company should provide a complete justification of cost recovery or deferred accounting in the next rate case,

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[499] *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, FINDINGS OF FACT CONCLUSIONS AND ORDER, Docket No. E001/GR-10-276 (Aug. 12, 2011) (*hereinafter* E001/GR-10-276 ORDER).
[500] E001/GR-10-276 ORDER.
[501] Ex. 99, Clark Direct at 34.
[502] Ex. 370, Lindell Direct at 40.

i.e., the current proceeding.[503] The Company complied with the Commission's directive by providing the requisite justification in the direct and rebuttal testimony from four Company witnesses.[504]

284. Second, the OAG suggested the Company could have brought a Notice of Changed Circumstances earlier and thereby avoided certain Prairie Island EPU Project costs, but the OAG does not specify which costs could have been avoided.[505]

285. The Company argued that the record demonstrates that given the changing circumstances experienced throughout 2011-2012, the Company's actions were appropriate. At the time of the Company's March 2012 Notice of Changed Circumstances filing, the Company continued to identify PVRR benefits for the Prairie Island EPU Project,[506] and the Department and other parties independently concluded at that time that the Prairie Island EPU Project should proceed.[507] In addition, the Company had both effectively suspended the Prairie Island EPU Project by the end of 2011 and provided extensive changed circumstance information in its December 2011 update to its 2010 Resource Plan.[508] Given that it was not clear even a year later, in late 2012, that the Prairie Island EPU Project should be cancelled,[509] the timing of the Company's Notice of Changed Circumstances filing and Company's actions were prudent and suspension had virtually no impact on Prairie Island EPU Project costs.

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503 ORDER IN 2013 RATE CASE at 54.
504 *See* Ex. 99, Clark Direct; Ex. 100, Clark Rebuttal; Ex. 48, Alders Direct; Ex. 49, McCall Direct; Ex. 45, Weatherby Direct, Ex. 47, Weatherby Rebuttal.
505 Ex. 370, Lindell Direct at 38.
506 Ex. 48, Alders Direct at 16, 18.
507 Ex. 48, Alders Direct at 19; *see also In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE – DIVISION OF ENERGY RESOURCES, Docket No. E002/CN-08-509 (June 12, 2012).
508 Ex. 48, Alders at 16.
509 Ex. 48, Alders at 20-21.

286. Third, the OAG argued that the Company could not have created a regulatory asset consistent with FERC rules and generally accepted accounting principles (GAAP) unless it had a specific Commission order permitting deferral.[510]

287. Regulated companies must close their books at the end of their fiscal year, and utilize regulatory assets to account for the likelihood a regulatory body will decide rate recovery of accumulated costs in a future period.[511] The creation of a regulatory asset does not govern future rate recovery decisions, but rather recognizes that rate recovery has yet not been resolved.[512]

288. Here, the Company accounted for the accumulated Prairie Island EPU Project costs at the end of 2012 in a manner consistent with GAAP and FERC accounting rules, after consultation with independent external auditors.[513] The Company reassessed the situation at the end of 2013 and again concluded rate recovery would be decided in a future year.[514] In each instance, the Company's external auditors did not take exception to either the Company's GAAP-basis or FERC-basis financial statements.[515]

289. Because establishing a regulatory asset for financial accounting purposes does not dictate the Commission's ability to decide rate recovery matters, the OAG's argument does not affect cost recovery for the Prairie Island EPU Project costs in this proceeding.

290. Finally, the OAG argued the Company should be required to permanently write off $10.1 million of Prairie Island EPU Project costs because the Company recorded a regulatory asset at the end of 2012 (when the Company needed to close its books for financial accounting purposes) and took a $10.1 million pretax

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510 Ex. 370, Lindell Direct at 41.
511 Tr. Vol. 1 at 181 (Weatherby).
512 Tr. Vol. 1 at 181 (Weatherby).
513 Tr. Vol. 1 at 181 (Weatherby).
514 Tr. Vol. 1 at 181 (Weatherby).
515 Tr. Vol. 1 at 181 (Weatherby); Ex. 47, Weatherby Rebuttal at 4.

charge to reflect uncertainty whether the Company would earn a return on the Prairie Island EPU asset.[516] Thus, the OAG suggests the Company cannot recover these dollars for ratemaking purposes because it already "wrote them off" for financial accounting purposes.

291. The Company explained that the $10.1 million pretax charge does not represent a "write off" of actual Prairie Island EPU Project costs; rather, under GAAP it accounted for cost recovery over at least 12 years without earning a return.[517] The $10.1 million pretax charge "reflects that we would essentially lose some of the value of our investment by delaying rate recovery into a future period without earning a carrying charge on the asset."[518]

292. The OAG's recommendation should not be accepted because a disallowance of a $10.1 million portion of total Prairie Island EPU Project costs plus no earn a return on the asset would mean that the Company would take a $10.1 million impairment charge in addition to the $10.1 million pretax charge.[519] This result is inconsistent with the Company's prudent project management and reasonable project costs.

4. Amortization of Cancelled Project Costs

293. In the initial filing, the Company proposed to amortize the costs of the Prairie Island EPU Project over 12 years with a return on the asset, or, in the alternative, to amortize the project costs (with AFUDC) over six years without earning a return on the asset.[520]

294. The Company stated that its proposals to recover Prairie Island EPU Project costs over 12 years with a return on the asset, or over 6 years with no return, are consistent with Commission precedent. The Company noted that amortization

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516 Ex. 370, Lindell Direct at 41-44.
517 Ex. 47, Weatherby Rebuttal at 6; Tr. Vol. 1 at 182 (Weatherby).
518 Tr. Vol. 1 at 182 (Weatherby).
519 Tr. Vol. 1 at 182 (Weatherby).
520 Ex. 99, Clark Direct at 41.

over 12 years is a longer amortization schedule than the Commission approved in 2006 for costs associated with the Company's cancelled Private Fuel Storage project,[521] and longer than the amortization period for the costs of the cancelled portion of Otter Tail Power's Big Stone II project.[522]

295. In surrebuttal, the Department indicated that amortization of Prairie Island EPU Project costs over the life of the plant with a debt-only return would be acceptable if the Commission determines a debt-only return would be preferable, and that the appropriate debt return percentage would be 2.24 percent.[523]

296. During the evidentiary hearing, the Company accepted the Department's proposal in the interest of resolving this issue and for the further benefit of our customers.[524] The Company stated, however, that if the Department's proposal is not accepted, the Company believes that recovery of the full Prairie Island EPU Project costs over 12 years with a return on the asset would be appropriate.[525]

5. Conclusion

297. Amortizing Prairie Island EPU Project costs over the remaining life of the Plant with a 2.24 percent debt return appropriately balances stakeholder interests without discouraging utilities' willingness to propose cancellation of a project.

298. The OAG's and ICI's additional adjustments are not warranted in light of the applicable cost recovery standard, the reasonableness of the costs, and the Company's prudent management of the Prairie Island EPU Project.

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521 *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, Docket No. E-002/GR-05-1428 (Sept. 1, 2006).
522 *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 11, Docket No. E-017/GR-10-239 (Apr. 25, 2011).
523 Ex. 442, Lusti Surrebuttal at 6-7.
524 Tr. Vol. 2 at 112 (Clark).
525 Company Initial Brief at 78.

B. CWIP and AFUDC (Issue #63)

1. Background

299. CWIP and AFUDC are used to account for and recover the cost of capital during construction. CWIP represents the accumulation of costs for projects under construction that will be capitalized and then depreciated over time once the projects are put in service.[526] AFUDC represents funds that the utility uses to finance construction projects.[527]

300. In the Company's last rate case, the OAG raised certain issues related to the Company's accounting for CWIP and AFUDC – namely, that "the Company has not provided any justification for short term projects to be included in CWIP" and "the Company has not complied with the FERC accounting rules regarding the inclusion of CWIP in rate base and the calculation of AFUDC."[528] The Commercial Group similarly contested the Company's accounting for CWIP.[529] After reviewing the arguments of the Parties, the ALJ made the following findings:

> 626. The Company responded that its treatment of CWIP and AFUDC conform to the Commission's established policies. The Company also maintained that its treatment of these items is consistent with FERC's Uniform System of Accounts. The Company noted that CWIP and AFUDC are authorized by statute, commonly included in rates, and audited by FERC. The Company asserts that the methods it uses for CWIP and AFUDC are fair to both the Company and its customers.
>
> **ii. Conclusion**
>
> 627. The Company has shown that its proposed inclusion of CWIP and AFUDC is consistent with FERC accounting requirements and past Commission practice. None of the other parties have demonstrated that any change to the

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526 Ex. 370, Lindell Direct at 17.
527 Ex. 370, Lindell Direct at 17.
528 ALJ REPORT IN 2013 RATE CASE at 129.
529 ALJ REPORT IN 2013 RATE CASE at 129.

> Company's accounting for CWIP and AFUDC is necessary to meet applicable legal requirements. Including CWIP in the rate base and providing AFUDC in the manner proposed by the Company is an appropriate exercise of the Commission's discretion under Minn. Stat. § 216B.16, subds. 6 and 6a.[530]

301. Upon review of these recommendations, the Commission concluded that it would permit inclusion of CWIP and AFUDC in that case but would require "a more detailed explanation of the Company's CWIP and AFUDC practices in its next rate case."[531] The Commission therefore ordered that:

> 52. In the initial filing in its next rate case, Xcel shall provide evidence of FERC's accounting requirements for CWIP/AFUDC and demonstrate that it has met the FERC requirements. It shall also address whether a minimum dollar level should be set for projects in CWIP.[532]

302. In this proceeding, the Company offered detailed testimony through Company witness Ms. Lisa Perkett as well as AFUDC and FERC accounting expert Mr. James Guest, explaining (i) the Company's AFUDC and CWIP accounting practices, (ii) how the Company complies with FERC accounting requirements, Minnesota statutes, and Commission precedent regarding AFUDC and CWIP; (iii) why it is neither necessary nor appropriate to establish a minimum dollar level for projects for which CWIP is included in rate base.[533]

303. Ms. Perkett explained that the Company's inclusion of CWIP in rate base is subject to a revenue requirement offset of AFUDC incurred in the year, which effectively eliminates the cost of financing construction from the revenue requirement during the construction period.[534] The utility is then allowed to include AFUDC in

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530 ALJ REPORT IN 2013 RATE CASE at 130.
531 ORDER IN 2013 RATE CASE at 10.
532 ORDER IN 2013 RATE CASE at 54.
533 Ex. 92, Perkett Direct at 51-63; Ex. 91, Guest Direct *passim*.
534 Ex. 92, Perkett Direct at 53.

the final cost of the asset at the end of construction.[535] As a result, these costs are deferred and amortized over the life of the asset after being placed in service.

2. OAG's and the Commercial Group's Position

304. The OAG contends that the Company's accounting for CWIP and AFUDC violates FERC requirements because FERC limits CWIP to 50 percent in rate base, allows either CWIP or AFUDC in rate base but not both, and disallows AFUDC during project interruptions.[536]

305. The OAG also argued that the purpose of AFUDC is to recognize the need for external funding, yet the Company accrues AFUDC on virtually all CWIP projects despite the fact that it has substantial internal funding available and all projects do not require external financing.[537]

306. The OAG recommended: (1) CWIP should not be included in rate base with an AFUDC offset to the income statement, but AFUDC should be deferred for recovery once the asset goes in service; (2) AFUDC should only be allowed on capital projects costing more than $25 million; (3) the AFUDC rate should not be set in accordance with FERC requirements (which recognize the cost of short-term debt first and then a weighted average of long-term debt and equity); rather, the AFUDC rate should be based on a simple average of the cost of short term debt and long term debt; and (4) AFUDC should be disallowed for the Prairie Island EPU Project for 2011 and 2012.[538]

307. The Commercial Group also recommended excluding CWIP from rate base, arguing the inclusion of CWIP charges ratepayers for assets during construction

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[535] Ex. 92, Perkett Direct at 54.
[536] Ex. 370, Lindell Direct at 16-29.
[537] Ex. 370, Lindell Direct at 23-24.
[538] Ex. 320, Lindell Surrebuttal at 22. In Direct Testimony, Mr. Lindell argued that AFUDC should not be permitted at all for the Prairie Island EPU, for the Monticello LCM/EPU project during the period the EPU portion was not in service, or for Sherco 3 during the period of its extended outage. It appears that Mr. Lindell modified that position in his Rebuttal Testimony, which only discusses a more limited disallowance of AFUDC during 2011 and 2012 for the Prairie Island EPU Project.

that are not yet used and useful.[539] The Commercial Group noted that CWIP shifts to ratepayers risks that are traditionally assumed by utility investors, and if a project is delayed or not completed, ratepayers have no resource for recovering what they have paid in rates for CWIP.[540] The Commercial Group did not address the reduction in net income resulting from the AFUDC offset but it is assumed that the Commercial Group is proposing the elimination of both CWIP and the AFUDC offset.[541]

3. Company's Position

a. Company's CWIP/AFUDC Accounting Complies with FERC

308. In detailed Direct Testimony, the Company explained its treatment of AFUDC and CWIP as consistent with FERC accounting standards. The fundamental process is consistent with Minnesota statutes and the FERC Uniform System of Accounts, and involves inclusion of CWIP in rate base subject to an offset by AFUDC.[542] The purpose of combining the AFUDC offset with the accumulation and capitalization of AFUDC is to avoid the cost of a current return on CWIP that would occur if CWIP was included in rate base without the AFUDC offset, and at the same time include these financing costs in the total cost of the project.[543] The Company explained that offsetting AFUDC combined with capitalization of these costs is not only consistent with FERC and long-standing state methodology, but also serves to defer and amortize these costs over the life of the asset through the recording of book depreciation expense after the asset is placed in service.[544]

309. FERC mandates the appropriate accounting in the Uniform System of Accounts (USofA), which the Commission adopted in Rule 7825.0300 as the basis for the financial data that is the foundation for rate making. The Minnesota treatment of

[539] Ex. 225, Chriss Direct at 10-11.
[540] Ex. 225, Chriss Direct at 10-11.
[541] Ex. 225, Chriss Direct at 10-11; Ex. 94, Perkett Rebuttal at 14-38.
[542] Ex. 92, Perkett Direct at 54-55.
[543] Ex. 92, Perkett Direct at 56.
[544] Ex. 92, Perkett Direct at 56.

AFUDC in ratemaking is in line with the USofA.[545] Moreover, while FERC typically does not allow CWIP in rate base, it also does not use an AFUDC offset and allows a higher rate of return over the life of the asset.[546]

310. The difference between the FERC method and the Company's longstanding treatment of AFUDC and CWIP is, in general, solely related to timing of the recovery.[547] The Company noted, however, that utilizing the longstanding Minnesota method in this proceeding in a manner consistent with FERC's AFUDC rate would increase the revenue requirement in 2014 by $8.5 million, and would increase the revenue requirement in 2015 by $12.4 million.[548] Based on this fact, the Company concluded that Minnesota method not only encompasses a balanced approach of applying the Company's full cost of capital to all investments while allowing full recovery of financing costs consistent with the FERC method, it also reduces the revenue requirement in this proceeding as compared to the FERC method.[549]

b. Proposed Minimum for Projects in CWIP

311. The OAG recommended that only projects in excess of $25 million should accrue AFUDC because "smaller projects would be financed with cash from operations and would not require external financing."[550]

312. In Direct Testimony, the Company explained that:

> The standard in Minnesota has been to include all investment in CWIP in rate base but to exclude less costly, short duration projects from the AFUDC offset and, consequently, from accumulating and capitalizing AFUDC. This practice provides a balanced approach that properly includes all investment in rate base while eliminating the

545 Ex. 94, Perkett Rebuttal at 19.
546 Ex. 94, Perkett Rebuttal at 17-18, 25.
547 Ex. 94, Perkett Rebuttal at 25.
548 Ex. 94, Perkett Rebuttal at 25.
549 Company Initial Brief at 86.
550 Ex. 320, Lindell Direct at 28; Ex. 323, Lindell Surrebuttal at 2.

> additional cost of accumulated AFUDC for projects that should be considered in service almost immediately.[551]

313. The Company also countered that the OAG's recommendation ignores that the Company first uses short-term debt to finance construction and then uses a mix of long-term debt and equity to provide capital.[552] It also ignores that retail rates are set such that revenues equal costs, including depreciation and a return on equity, and retail revenues cannot be used as a replacement for capital.[553]

314. The Company further stated that the effect of the OAG's recommendation would be to exclude 62 percent of CWIP investment, or approximately $441 million in capital costs during construction.[554] This exclusion would occur notwithstanding FERC's past findings that "carrying costs on the investment are as much a legitimate expense of the project as are the more tangible costs such as parts and materials."[555] Because the Company is entitled to recover its costs of capital in rates and maintain a fair opportunity to earn a reasonable return, the OAG's threshold proposal is inappropriate.

c. OAG's Method to Calculate AFUDC Rate

315. The OAG recommends that equity not be used in the calculation of the AFUDC rate.[556] Rather, the OAG suggests that a blended short-term debt and long-term debt rate, weighted at 50 percent each, which produces a rate of 2.62 percent, should be used.[557]

316. The Company opposed the OAG's AFUDC rate because it would depart from long-standing Commission precedent, it would be inconsistent with

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551 Ex. 92, Perkett Direct at 64.
552 Ex. 94, Perkett Rebuttal at 30.
553 Ex. 94, Perkett Rebuttal at 31.
554 Ex. 92, Perkett Direct at 29.
555 In *Northern States Power Co.*, 17 FERC ¶ 61,196, at 61,382-83 (1981) (Opinion No. 134).
556 Ex. 370, Lindell Direct at 28.
557 Ex. 370, Lindell Direct at 28.

FERC policy and practice, and would also substantially lower the Company's AFUDC rate of 6.792 percent.[558]

317. The Company supported its methodology for calculating AFUDC by noting that the Company's methodology to calculate AFUDC is the same as used in every rate case since 1977 and that the Company's calculation of the AFUDC rate has always been calculated "in conformance with FERC Order 561 issued February 2, 1977."[559]

d. AFUDC for Prairie Island EPU Project

318. In response to the OAG's claim that the Company should not have accumulated AFUDC for the Prairie Island EPU Project for 2011 or 2012, the Company argues that the OAG misconstrues both FERC accounting rules and the timing of the cancellation.[560]

319. The Company noted that relevant precedent establishes that AFUDC accrual is appropriate through project cancellation, even where there is a period of interruption.[561]

320. The Company also explained that the OAG's recommendation assumes that the Prairie Island EPU Project was cancelled in 2011 when that was not the case. The Company clarified that activities furthering the Prairie Island EPU Project continued in 2011 and 2012 for two primary reasons: (1) The Prairie Island EPU Project remained viable, and in fact there was no time at which it was clear it should be cancelled;[562] and (2) It was more prudent to continue the third-party contract and receive the final deliverables – especially if the Prairie Island EPU Project continued

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558 Ex. 92, Perkett Direct at 57.

559 Ex. 92, Perkett Direct at 57 (citing E002/GR-81-342, FINDINGS OF FACT CONCLUSIONS OF LAW AND ORDER, dated June 25, 1982, at 25; 75 P.U.R. 4th 538 at p. 15, ORDER dated June 2, 1986; Tr. Vol. 2 at 191 (Perkett)).

560 Company Initial Brief at 94.

561 Ex. 94, Perkett Rebuttal at 34; *See* Company Initial Brief at 94-95.

562 Ex. 48, Alders Direct at 18, 20-21; Ex. 100. Even in October 2012, when the Company filed its Supplemental filing in the Prairie Island EPU changed circumstances proceeding, the PVRR benefits of the Program remained marginally positive. Ex. 48, Alders Direct at 20-21.

as expected – than to cancel the contract, pay a termination fee, and receive no deliverables.[563] Finally, the Prairie Island EPU Project was not formally cancelled until February 2013, when the Commission its Order Terminating the Certificate of Need Prospectively.[564] By that time, the Company had already terminated AFUDC accrual consistent with the Commission's vote on the matter in December 2012.[565]

4. Conclusion

321. The record does not support the recommendations of the OAG or the Commercial Group related to CWIP and AFUDC.

322. The Company accounts for CWIP and AFUDC appropriately, consistent with FERC accounting requirements, Minnesota statutes, and longstanding Commission-approved practice. The Company's inclusion of CWIP in rate base with an AFUDC offset is balanced and appropriate for all stakeholders, while ensuring the Company recovers its full financing costs. The Company's AFUDC rate is likewise consistent with FERC rules and is reasonable, and the Company's AFUDC accounting for the Prairie Island EPU Project is consistent with both FERC requirements and the circumstances surrounding the cancellation.

C. MYRP: Rate Moderation Proposal – TDG Theoretical Depreciation Reserve Surplus (2014 and 2015 Step)[566] (Issue #9)

323. In the Company's last rate case, the Commission required amortization over eight years of the difference between the Company's recorded book depreciation reserve compared to a theoretical book reserve for the Company's transmission, distribution, and general (TDG) assets.[567] As a result, the Company began amortizing the reserve surplus of approximately $261 million over eight years beginning in

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563 Ex. 49, McCall Direct at 33-34, 38.

564 *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY, Docket No. E002/CN-08-509 (Feb. 27, 2013) (emphasis added).

565 Ex. 45, Weatherby Direct at 5.

566 The rate moderation proposal regarding DOE Settlement Funds is discussed under issue # 34 and Nuclear Theoretical Depreciation Reserve is discussed under issue # 75.

567 Ex. 99, Clark Direct at 27.

2013.[568] At the beginning of 2014 there is $228.5 million remaining to be amortized over the next seven years.[569]

324. To moderate the impact of rate increases on its customers as part of its MYRP, the Company proposed to accelerate return of the depreciation reserve surplus to customers over the next three years: 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016.[570] The Company stated that this amortization pattern is intended to result in stable and predictable rate increases for its customers.[571]

325. The Department proposed an alternative 50 percent, 40 percent, and 10 percent amortization schedule to accelerate the benefits to the years at issue in this case.[572] The Department, however, acknowledged that the Company's initial 50 percent, 30 percent, and 20 percent proposal would also be reasonable.[573]

326. The Company also provided as an illustrative example a 50-0-50 percent schedule.[574]

327. The OAG recommended that the Commission deny the Company's proposed change in the amortization of the depreciation reserve surplus. The OAG stated that the Company's proposal does not reduce customers' rates but simply shifts costs recovery to the future.[575] The OAG also opposed the Company's proposal because it argued that it was inconsistent with the Company's position in prior rate cases.[576]

328. The Company disagreed with the OAG's recommendation stating that: (1) rate moderation tools can be utilized to provide more predictable year-over-year rates, enhance regulatory efficiency, and reduce the impacts of our current investment

568 Ex. 99, Clark Direct at 27.
569 Ex. 99, Clark Direct at 27.
570 Ex. 99, Clark Direct at 28.
571 Ex. 25, Sparby Direct at 28.
572 Ex. 431, Campbell Direct at 94.
573 Ex. 431, Campbell Direct at 94.
574 Company Initial Brief at 98.
575 Ex. 370, Lindell Direct at 13.
576 Ex. 370, Lindell Direct at 13-16.

cycle on our customers and (2) that the Company has supported accelerated amortization options in prior rate cases.[577]

329. The Commission has the discretion to direct the use of the rate moderation tools in the manner it deems most appropriate, once final rates are determined. These rate moderation tools include ordering a specific theoretical reserve consumption pattern that it determines best moderates rates once the outcome of the key disputed revenue requirement issues are resolved. The Commission may also conclude there is no need to refund the 2015 DOE settlement credits to customers after resolving the disputed revenue requirement issues. The Commission could also consider other solutions such as moving rate recovery of the Border and Pleasant Valley wind projects from the 2015 Step to the RES rider.

D. Nuclear Theoretical Depreciation Reserve (2014) (Issue #75)

1. Background

330. The depreciation a utility accrues over the course of an asset's life is to cover the cost of the asset plus retirement costs. Depreciation is based on the expected useful life of an asset and the estimated net salvage value.

331. Depreciation is defined in the Commission's rules as "the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance."[578]

332. "Depreciation accounting" is a "system of accounting which aims to distribute cost or other basic value of tangible capital assets, less salvage, if any, over the estimated useful life of the unit, which may be a group of assets, in a systematic and rational manner. It is a process of allocation, not valuation."[579]

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[577] Ex. 100, Clark Rebuttal at 39-40.
[578] Minn. R. 7825.0500, subp. 6.
[579] Minn. R. 7825.0500, subp. 7.

333. At any point in time, the current expected useful life and estimated net salvage can be used to estimate where the reserve would be assuming this current information was used to calculate depreciation throughout time. The resulting calculated reserve is the "theoretical reserve."[580]

334. When a utility's actual reserve is greater than the theoretical reserve, this difference is referred to as a surplus. A surplus does not immediately mean that the utility recovered more depreciation from customers than was necessary or prudent at the time because the actual reserve is based on the estimated useful life and net salvage at the time it was accrued rather than the current estimated useful life and net salvage. Nor does a surplus indicate that excess funds may exist as it would be rare for actual depreciation to match the theoretical reserve. As a result it is not always clear when or to what extent a surplus depreciation reserve is "real."

335. In the Company's prior rate case, XLI and the MCC (i) argued that the Company had a surplus of $265 million for Transmission, Distribution, and General plant (TDG) and $219 million for nuclear production plant; and (ii) proposed that the Company amortize these funds over a five-year period.

336. The ALJ and Commission concurred that a TDG surplus reserve did exist, noting that (as in the current rate proceeding) "[r]egarding Xcel's transmission, distribution, and general plant, no party disputes that Xcel has accrued a depreciation surplus or that the surplus should be amortized."[581]

337. The Commission, however, rejected XLI's proposal with respect to nuclear generating plants.[582] The Commission observed "the preponderance of the evidence indicates that these reserves appropriately reflect the cost of production

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[580] ORDER IN 2013 RATE CASE at 26.
[581] ORDER IN 2013 RATE CASE at 28.
[582] ORDER IN 2013 RATE CASE at 29.

plant retirements, including interim retirements, as explained by Xcel and the Department."[583]

338. In addition, the Commission concurred with the ALJ that it was "prudent to avoid accelerating the depletion of the production plant depreciation reserves when Xcel has just made large investments in its nuclear generators, increasing the amount of production plant it has to depreciate."[584]

339. Finally, the Commission noted that the nuclear production plant decision was not intended to preclude "continued monitoring and analysis," and directed the parties to explore the matter more fully in this case.[585]

340. In this proceeding, the Company calculated a nuclear depreciation reserve of $72.5 million (Minnesota jurisdiction) but noted that the existence and amount of the calculation depends of several current assumptions including remaining life, interim retirements and removal, and net salvage.[586]

2. XLI's Position

341. XLI claims that the Company miscalculated the nuclear theoretical depreciation reserve such that the figure is not $72.5 million (Minnesota jurisdiction) but is instead $208 million (Minnesota jurisdiction).[587] XLI's calculation of theoretical reserve excludes interim capital additions and uses vintage accounting.[588]

342. XLI's proposed to reduce the Company's revenue requirement by accelerating amortization of its calculated theoretical nuclear depreciation reserve surplus of $208 million to a five-year term.[589]

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583 ORDER IN 2013 RATE CASE at 29.
584 ORDER IN 2013 RATE CASE at 27, 29.
585 ORDER IN 2013 RATE CASE at 29.
586 Tr. Vol. 2 at 66-68 (Perkett); Perkett Direct at 50-51.
587 Ex. 264, Pollack Opening Statement at 1.
588 Ex. 264, Pollack Opening Statement at 1.
589 Ex. 260, Pollack Direct at 9-19.

343. The Company and the Department both disagree with XLI's proposal based on XLI's assumptions about the existence of a surplus, its calculation methods, and XLI's recommendation to implement a five-year amortization period.

3. Department's Position

344. The Department opposed expansion of the use of amortization of theoretical depreciation reserve surplus beyond the Commission's action in the Company's prior rate case, which excluded nuclear plant depreciation reserve.[590] Specifically, Department witness Ms. Nancy Campbell testified that "this short-term rate reduction would be short sighted and would result in higher rates for ratepayers in the long run."[591] The Department urged the Commission to calculate the useful life of nuclear facilities based on: (1) the annual and five-year depreciation studies and (2) the integrated resource plan and not to recalculate the remaining life in this case based on theoretical information.[592]

345. The Department also contended that the XLI's claim of overpayment is incomplete and incorrect because it does not consider what is occurring during the current rate case in the 2014 test year and the 2015 Step year and what is expected over the remaining lives of the nuclear assets. The Department stated that is it not reasonable to conclude that there is a surplus in nuclear depreciation reserve, particularly in light of the Company's request for recovery of costs related to the cancelled Prairie Island EPU and the Monticello LCM/EPU Program.[593]

4. Company's Position

346. The Company disagreed with XLI's assumptions used to calculate the alleged surplus. The Company contended that XLI's use of vintages to determine depreciation expense for nuclear facilities is inappropriate. Company witness, Ms.

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590 Ex. 434, Campbell Rebuttal at 2-4.
591 Ex. 434, Campbell Rebuttal at 2.
592 Ex. 434, Campbell Rebuttal at 2-4.
593 Ex. 434, Campbell Rebuttal at 3.

Perkett explained that the vintage method works well where there are a large number of essentially identical assets such that a reliable average life can be determined for each vintage of asset type.[594] The vintage method also works well for assets that are being replaced at the end of their life with a like kind of asset with similar life expectations.[595]

347. In contrast, the remaining life for assets in nuclear facilities is determined more by the license life for the unit in which the asset is used than the standalone life of the asset.[596] As Ms. Perkett explained that "a pump with an individual life expectation of 40 years would not have this same expectation if it is installed 15 years before the nuclear unit's license expires. In that example, the pump would have a 15-year life expectation."[597] Consequently, it is more accurate to base nuclear reserve calculations on reasonable assumptions about remaining operating license lives, where possible, than to use the vintage method to develop a surplus calculation and propose accelerated amortization based on asset life regardless of licensing life.[598]

348. Company also stated that it would not be prudent to accelerate amortization of the nuclear costs when the Company has recently "made large investments in its nuclear generators, increasing the amount of production plant it has to depreciate."

349. The Company acknowledged that there is another way to reduce the current amount of depreciation without harming future customers.[599] The Company explained that the method, which would require approval to deviate from the Generally Accepted Accounting Principles (GAAP), would employ regulatory

[594] Ex. 94, Perkett Rebuttal at 8-9.
[595] Ex. 94, Perkett Rebuttal at 9.
[596] Ex. 94, Perkett Rebuttal at 9.
[597] Ex. 94, Perkett Rebuttal at 9.
[598] Ex. 94, Perkett Rebuttal at 9.
[599] Ex. 94, Perkett Rebuttal at 13-14.

accounting to depreciate nuclear units over a remaining life longer than the license life.[600] No other party expressed interest in this proposal.

5. Conclusion

350. The Company has established by a preponderance of the evidence that there is no surplus depreciation reserve for nuclear assets because the existing reserve is needed to account for interim plant retirements and interim salvage of nuclear assets. Moreover, the Company will be making significant investments in its nuclear assets in the near future and these expenses will require additional depreciation expense. As a result, the Commission should decline to accept XLI's proposal to amortize the claimed nuclear depreciation reserve over five years.

E. Changes to In-Service Dates for Capital Projects (2014 and 2015 Step)(Issue #11)

1. Department's Position

351. In Direct Testimony, the Department proposed a downward adjustment to the Company's revenue requirement to reflect capital projects with updated in-service dates that moved outside the test year, or Step year, as applicable.

352. These projects included $67.3 million in capital additions that moved outside the 2014 test year, and disallowance of those projects would result in a $2.18 million reduction to the 2014 revenue requirement.[601]In addition, in-service date changes for seven of the 2014 projects also impact the 2015 Step, and two additional projects have a revised in-service date outside the 2015 Step year.[602]These projects total an additional $3.8 million in capital additions, and disallowance would result in a $2.05 million revenue requirement reduction for 2015.[603]

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600 Ex. 94, Perkett Rebuttal at 13-14.
601 Ex. 429, Campbell Direct at 153 and Schedule 28 at 3.
602 Ex. 429, Campbell Direct at 153 and Schedule 28 at 3.
603 Ex. 429, Campbell Direct at 153 and Schedule 28 at 3.

2. Company's Position

353. The Company objected to the Department's proposed reductions stating that it is inconsistent with the representative test year concept.

354. The Company cited that the Commission has previously accepted such changes to in-service dates as part of the test year concept:

> [T]he Commission has noted that isolated changes in test year data can skew the rate case process for or against the Company, for or against ratepayers. '…the test year method by which rates are set rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical – some favoring the Company, others not. Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year process. Anomalies are likely to exist in and beyond any test year.'[604]

355. Company witness Mr. Christopher B. Clark testified that the shift of specific capital projects out of the 2014 test year and the 2015 Step does not reflect a significant percentage of capital projects or capital expenditures, and the capital expenditures that have been shifted out of the 2014 test year and 2015 Step have been offset by other capital projects that are being shifted into the 2014 test year and 2015 Step.[605]

356. The Company stated that changes to in-service dates are part of the dynamic nature of the utility business which can be unpredictable due to condition of equipment, severe weather events, changes to business or customer priorities, or emerging regulatory requirements and that any one of these types of changes can

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[604] *In the Matter of the Complaint by Myer Shark et al Regarding Xcel Energy's Income Taxes,* ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4, Docket No. E,G002/C-03-1871 (Oct. 1, 2004) (quoting *In the Matter of the Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Authority to Changes its Schedule of Rates for Retail Electric Service in the State of Minnesota,* ORDER AFTER RECONSIDERATION AND REHEARING, Docket No. E-015/GR-87-223 (May 16, 1988)).

[605] Ex. 100, Clark Rebuttal at 16-18.

impact the timing of capital project completion (either through delay or acceleration).[606]

357. The Company also provided detailed support illustrating when planned project in-service dates change, the Company allocates the capital budget to fund like-kind replacements (work similar in scope, timing, and cost to the original project); emergent work (work that was not originally planned but becomes necessary to complete); and normal business changes (reallocations based on normal changes in project priorities due to changing circumstances).[607]

358. The Company also noted that for capital projects in the 2015 Step, no adjustment is needed because of the refund mechanism applicable to these projects in the event a Step project is delayed or cancelled.[608] The Company further stated that the 2015 Step projects represent a limited percentage of total 2015 costs and do not reflect all of the Company's capital additions in that year.[609]

359. The Company also argued that to the extent the Commission considers changes in in-service dates, the Company should be allowed to add new capital projects that have moved into the test year or Step year. The Department did not accept this proposal claiming that allowing additional capital projects into the case would unfairly burden parties and would not be in the public interest.[610]

3. Conclusion

360. The Company's capital revenue requirement is representative of the capital projects that will go into service during the 2014 test year and the 2015 Step year and therefore the Department's proposed revenue requirement reductions should not be adopted.

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[606] Ex. 94, Perkett Rebuttal at 38-39.
[607] Ex. 94, Perkett Rebuttal at 39-42.
[608] Ex. 100, Clark Rebuttal at 18-19.
[609] Ex. 100, Clark Rebuttal at 18-19.
[610] Ex. 429, Campbell Direct at 153; Ex. 450, Campbell Opening Statement at 8.

F. Interest Rate on Interim Rate Refund (Issue #66)

361. Minn. Rule 7825.3300 establishes the interest rate required to be paid on an interim rate refund. The rule states in part:

> Any increase in rates or part thereof determined by the commission to be unreasonable shall be refunded to customers or credited to customers' accounts within 90 days from the effective date of the commission order and determined in a manner prescribed by the commission including interest at the average prime interest rate computed from the effective date of the proposed rates through the date of refund or credit.

The rule requires the utility to refund the amount by which interim rates exceed final rates, plus interest, to reflect the fact that the Company, in effect, borrowed money from its customers during pendency of the interim rate period.

362. Minn. R. 7829.3200 allows the Commission to vary its rules when the following requirements are met: (A) enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule; (B) granting the variance would not adversely affect the public interest; and (C) granting the variance would not conflict with the standards imposed by law.

363. Based on the Commission's decision in the Company's last rate case, the OAG recommends the Commission vary its rule and increase the interest rate based on the Company's full weighted cost of capital (*i.e.*, the Company's overall rate of return).[611]

364. The Company argued that the present case is distinguishable from the prior rate case and that the requirements for varying the Commission's rule have not been met. The Company pointed out several differences.

365. First, the Company took a conservative approach with interim rates when compared to interim rate calculations provided under Minnesota law. The

[611] Ex. 370, Lindell Direct at 58-59.

Company took steps to ensure that its interim rates would be approximately half of its requested rate increase for the test year. Also, the Company did not seek an interim rate increase for the 2015 Step year.

366. Second, from a cost-of-service perspective, revenues from interim rates are equivalent to, and a trade-off for, short-term borrowing.[612] In the absence of the added revenues from interim rates, the Company would increase short term borrowing by the amount of those revenues on a dollar for dollar basis.[613]The Company's cost of short term borrowing, is 0.62 percent.[614] The Prime Rate, which is the rate the Company will pay on interim rate refunds pursuant to Commission rule, is 3.25 percent.[615] Thus, under the Commission Rule, the Company will pay far more in interest on interim rate refunds (3.25 percent) than it would cost for replacement short term borrowing (0.62 percent).[616]

367. Third, application of the Company's ROR to the entire refund would be inappropriate. The interim rate refund is based on the difference between (i) the Company's interim rate revenue requirement; and (ii) the final Commission-approved annual test year revenue requirement.[617] If the approved test year revenue requirement is reduced as a result of a reduction in the Company's allowed return on investment (ROR x rate base), the entire reduction in the Company's allowed return, including the ROR, is refunded to customers.[618] As a result, any refund to customers already reflects application of the Company's ROR for any reduction in allowed return.[619] The interest on the interim rate refund is in addition to the refund of any excess return (ROR x rate base).[620] The Company obtains recovery of its current

[612] Ex. 31, Tyson Rebuttal at 23-24.
[613] Ex. 31, Tyson Rebuttal at 23-24.
[614] Ex. 31, Tyson Rebuttal at 24.
[615] Minn. R. 7825.3300
[616] Ex. 31, Tyson Rebuttal at 24.
[617] Ex. 90, Heuer Direct at 38.
[618] Ex. 90, Heuer Direct at 38.
[619] Ex. 90, Heuer Direct at 38.
[620] Ex. 90, Heuer Direct at 38.

expenses but does not earn a return on current expenses.[621] The OAG's recommendation would, however, apply a level of interest to the current expenses that is equal to the Company's ROR.[622]

368. As the present case is distinguishable from the Company's prior rate case and the requirements of Minn. R. 7829.3200 have not been met, the Commission should not grant the variance.

G. Fuel Cost Recovery Reform (Issue #67)

369. XLI and MCC have raised the need for reforms of the Company's Fuel Clause Adjustment (FCA) mechanism.[623] The Department has also identified an interest in reforms to the FCA.[624] Since the FCA is separate rate mechanism from the base rates which are the subject of the instant rate case, the Company and the Department agree that the appropriate proceeding in which to address FCA matters is in the Annual Automatic Adjustment (AAA) proceeding.[625]

370. Because the Company did not include replacement fuel costs in this rate case and because the issue involves other investor-owned utilities, the AAA docket is a better forum to address reforms to the Company's FCA mechanism.

H. Sherco Unit 3 Outage-Replacement Fuel Costs (Issue #68)

371. MCC proposed that the replacement fuel costs for Sherco 3 be capitalized and recovered over the life of the respective plant.[626]

372. Both the Company and the Department agreed that these issues are most appropriately addressed in AAA proceedings.[627]

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[621] Ex. 90, Heuer Direct at 38.
[622] Ex. 90, Heuer Direct at 38.
[623] Ex. 260, Pollack Direct at 25-32; Ex. 343, Maini Direct at 41-43.
[624] *See* Ex. 412, Ouanes Rebuttal at 16.
[625] Ex. 100, Clark Rebuttal at 43; Ex. 412, Ouanes Rebuttal at 15.
[626] Ex. 340, Schedin Direct at 9, 13-14.
[627] Ex. 94, Perkett Rebuttal at. 54- 55; *See* Ex. 437, Lusti Direct at 68 (discussing the Sherco 3 replacement power costs are being addressed in the Company's current open AAA Docket).

373. The Company noted that these fuel costs were not included in the calculation of base rates in this case.[628]

374. The Company also stated that such costs should not be capitalized because the cost of replacement power should be covered by those customers who used the power during the outage rather than future customers.[629]

375. As replacement fuel costs were not included in the Company's initial filing, this is issue is more appropriately addressed in the AAA proceeding.

I. Corporate Aviation Costs (Issue #65)

376. The Company requested recovery of $954,425 for corporate aviation costs in its 2014 test year.[630] This amount represents half of the approximately $1.9 million that the Company has budgeted for corporate aviation in 2014.[631] The Company argued that its request to include 50 percent of the corporate aviation costs is reasonable and consistent with Commission precedent.[632]

377. The Company asserts that it obtains the following benefits from using corporate aviation costs: travel expense savings, employee time savings, increased in-flight productivity, scheduling convenience, reduced stress and post-trip fatigue, and personal security.[633]

378. To confirm these benefits, the Company commissioned a third-party cost-benefit analysis for corporate aircraft usage from January 2012 through June 2013.[634] The study showed that corporate aviation resulted in higher productivity since employees reach their destinations faster allowing them to maximize their work

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628 Ex. 100, Clark Rebuttal at 44; Ex. 97, Robinson Rebuttal at 25.
629 Ex. 100, Clark Rebuttal at 44.
630 Ex. 75, O'Hara Direct at 28.
631 Ex. 75, O'Hara Direct at 28.
632 Ex. 75, O'Hara Direct at 28-29; *see also* ALJ REPORT IN 2013 RATE CASE at findings. 593-598 (finding the Company has demonstrated the reasonableness of including fifty percent of corporate aviation costs in the 2013 test year budget and that the request is consistent with Commission precedent).
633 Ex. 75, O'Hara Direct at 29.
634 Ex. 75, O'Hara Direct at 29.

days and that employees are getting more work accomplished in transit.[635] The cost-benefit analysis concluded that on average, 68 percent of the Company's corporate aviation expenses from January 2012 to June 2013 were justified compared to commercial aviation services.[636]

379. The OAG raised three main concerns regarding the Company's corporate aviation costs: (i) the Company's cost per flight was excessive; (ii) many of the flights scheduled did not provide ratepayer benefits; and (iii) most of the flights recorded did not include a sufficient business purpose to determine whether the flight was necessary and prudent to provide utility service.[637]

380. Based on these reasons and a review of the Company's flight logs, the OAG recommended disallowing the majority of the corporate aviation costs and allowing recovery of $34,143.[638] The OAG's adjustment was calculated based on $300 per flight multiplied by the number of passengers per flight.[639] The OAG also proposed additional adjustments for personal travel, flights coded as business area travel, and costs for investor relations and aviation use.[640]

381. The Company countered that the OAG's calculation of aviation expenses does not take into account practical issues that affect ticket prices, different time periods between reservations and travel, and fees related to ticket changes and cancellations[641] nor does it account for increased productivity, time savings, avoided hotel charges, and any other benefit of corporate aviation.[642] In addition, the Company noted that the OAG's $300 per flight approach has been previously reviewed and rejected by the Commission.[643]

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635 Ex. 75, O'Hara Direct at 30.
636 Ex. 75, O'Hara Direct at 30-31.
637 Ex. 370, Lindell Direct at 50.
638 Ex. 370, Lindell Direct at 56-58.
639 *See* Ex. 370, Lindell Direct at 52.
640 *See* Ex. 370, Lindell Direct at 57-58.
641 Ex. 77, O'Hara Rebuttal at 7.
642 Ex. 77, O'Hara Rebuttal at 7.
643 2013 RATE CASE ORDER at 10-11.

382. The Company further argued that the OAG's disallowance for personal travel, flights coded as business area travel, and costs for investor relations and aviation use are also not well supported.

383. The Company stated that the flight logs show that the aircraft have the appropriate passengers on board and travel mostly between company locations. The Company acknowledged that "personal travel" is rare and it is only used when spouses of Company executive employees or members of the Xcel Energy Board of Directors accompany their employed spouses to business functions.[644]

384. With respect to the OAG's proposal to disallow the costs of 42 flights for which the business purpose was listed as "Aviation Use,"[645] the Company noted that these flights "are necessary to maintain the functionality of the aircraft and provide corporate aviation services."[646]

385. The Company noted that with respect to business area, executive travel, director travel, and manager travel, a valid business purpose is required for use of any of the corporate aircraft.[647]

386. The Company has demonstrated that it is reasonable to include $954,425 for corporate aviation costs in the 2014 test year. The Company's request is based on a detailed cost-benefit analysis and is consistent with Commission precedent.

J. Rate Case and Monticello Prudency Review Expense Amortization (2014) (Issue #8)

387. The Company's test year includes expenses totaling approximately $950,000 to account for the cost of conducting the Monticello Prudence Investigation proceeding (Docket No. E002/CI-13-754), as well as approximately $2.7 million in rate case expenses for this case.[648]

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[644] Ex. 77, O'Hara Rebuttal at 8.
[645] OAG Initial Brief at p. 24.
[646] Ex. 77, O'Hara Rebuttal at p. 11.
[647] Ex. 77, O'Hara Rebuttal at 12.
[648] Ex. 90, Heuer Rebuttal at 23; Ex. 438, Lusti Direct at 28.

388. The Company proposed to amortize the Monticello Prudence Investigation costs and rate case costs over two years, consistent with the likelihood the Company will file its next rate case in late 2015, using a 2016 test year.[649]

389. The Department agreed with the amount and the two-year amortization of rate case expenses.[650]

390. The Department agreed with the amount of Monticello Prudence Investigation expense included in the test year. [651]

391. However, the Department proposed to amortize Monticello Prudence Investigation costs over the remaining life of the Monticello facility (16.8 years) without a return, on the grounds that the prudence investigation pertains to the overall facility and will have ramifications over the life of the facility.[652]

392. The Department's recommendation decreases teat year rate case amortization expense by $418,452.[653]

393. The Company supported its proposed two-year amortization for the costs for the Monticello Prudence Investigation by noting that these costs are similar to rate case costs as they are relatively small in amount and pertain to a one-time investigation.[654] Thus while a rate case proceeding may also have long-term financial effects on a utility, amortization of rate case costs is typically limited to shorter periods to reflect the primary period affected by the proceeding.[655]

394. The Company argued that prudence investigation expenses should not be treated like capital costs, as these expenses do not affect plant operations and have no bearing on the remaining useful life of the facility.[656]

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649 Ex. 90, Heuer Rebuttal at 24.
650 Ex. 438, Lusti Direct at 28-29.
651 Ex. 438, Lusti Direct at 28-29.
652 Ex. 90, Heuer Rebuttal at 24; Ex. 442, Lusti Surrebuttal at 17-18.
653 Ex. 437, Lusti Direct at 29.
654 Ex. 90, Heuer Rebuttal at 25.
655 Ex. 90, Heuer Rebuttal at 24.
656 Ex. 90, Heuer Rebuttal at 24.

395. Finally, the Company claimed it would be inappropriate to require the Company to bear the Prudence Investigation costs over the life of the facility without providing a carrying charge to account for the time that the Company must wait before recovering the costs.[657]

396. Given the similarities between rate case costs and the Monticello Prudence Investigation costs, it is reasonable to amortize both costs over a two-year period.

K. Nuclear Refueling Outage Costs (Issue #64 and #27)

1. Accounting Methodology (Issue #64)

397. The Company supported continued use of the deferral and amortization method for nuclear refueling outage expenses as a means to promote stability, predictability, and fairness for ratepayers.[658] The Company stated that this methodology, which has been used since 2008, moderates rate increases by phasing them in over a longer period of time, moderates year-over-year variations, and matches the outage costs to the period during which the benefits from the outage occur.[659]

398. The OAG's primary concern is that the Company should not be allowed to earn a return on a normal expense, and that providing such a return gives the Company incentives to increase the scope of nuclear outage expenses.[660]

399. The OAG also objected to the Company's continued use of the deferral and amortization method for nuclear refueling outage costs as the OAG believes that the normalization method would be superior.[661] However, the OAG recommended that the Company be allowed to continue use of the deferral and amortization method

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[657] Ex. 90, Heuer Rebuttal at 24.
[658] Ex. 97, Robinson Rebuttal at 22.
[659] Ex. 97, Robinson Rebuttal at 22.
[660] Ex. 370, Lindell Direct at 45-47.
[661] Ex. 370, Lindell Direct at 47.

to set rates but that the Company not be allowed to earn a return on nuclear refueling outage costs.[662]

400. The Company responded that it is appropriate to allow return on these expenses under fundamental ratemaking principals.[663] The Company stated that when it uses funds to cover nuclear refueling outage costs prior to receiving funds from customers, standard ratemaking contemplate that the Company is entitled to earn a return on the unamortized balance net of accumulated deferred income tax.[664]

401. The Company also pointed out that it has an ongoing obligation by way of its May 1 Electric Jurisdictional Annual Report, to demonstrate that the nuclear refueling outage costs are reasonable and accurate.[665]

402. The Company has demonstrated that it is reasonable to include a carrying charge on the unamortized deferred balance of nuclear refueling outage costs as it represents the appropriate time-cost of money.

2. Cost Amortization (Issue #27)

403. The Company included $89.3 million in test year amortization expenses for nuclear refueling outages.[666] During discovery, the Company provided additional information related to the 2015 Step year nuclear outage amortization expenses.[667] This information showed that the amortization expenses for nuclear refueling outages decreased from 2014 to 2015. Based on this information, the Department recommended a $5.5 million reduction in revenue requirements for the 2015 Step.[668]

404. In Rebuttal Testimony, the Company disagreed with the Department's proposal, explaining that the Company included only a limited number of capital

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[662] Ex. 370, Lindell Direct at 47.
[663] Ex. 97, Robinson Rebuttal at 23-24.
[664] Ex. 97, Robinson Rebuttal at 23-24.
[665] Ex. 97, Robinson Rebuttal at 24.
[666] Ex. 52, O'Connor Direct at 119 and Sch. 16.
[667] Ex. 431, Campbell Direct at 63 and Sch. 12.
[668] Ex. 431, Campbell Direct at 67, 169-170.

projects.[669] The Company noted that the Department's proposal would expand the scope of the 2015 Step to include decreasing rate base components and expenses without including increasing rate base components and expenses.[670] The OAG disagreed with the Company's characterization of the 2015 Step and supported the Department's proposed $5.5 million adjustment.[671]

405. In Surrebuttal Testimony, the Department agreed with the Company and noted that the nuclear outage costs are separate O&M expenses not directly related to any of the 2015 Step capital project, and therefore no longer recommended the $5.5 million adjustment.[672]

406. In the evidentiary hearing, the Department noted that this issue is resolved between the Department and the Company.[673] The issue is unresolved between the OAG and the Company.[674] The OAG supports the Department's original recommendation of a $5.5 million revenue requirement reduction for 2015 Step.[675]

407. Nuclear amortization expense is a separate O&M item, which is not directly related to any of the 2015 Step capital projects. As a result, projected decrease in these expenses does not warrant the OAG's proposed adjustment to the 2015 Step revenue requirements.

L. Black Dog-Unit 2 and 5 Outage Costs (2014) (Issue #76)

408. Units 2 and 5 of the Black Dog Generating Plant experienced a three month outage ("Black Dog 5/2").[676]The outage lasted from late 2012 to early 2013

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669 Ex. 26, Sparby Direct at 11-12.
670 Ex. 26, Sparby Direct at 12; Ex. 100, Clark Direct at 35.
671 Ex. 322, Lindell Rebuttal at 6.
672 Ex. 435, Campbell Surrebuttal at 14-16; Ex. 442, Lusti Surrebuttal at 43.
673 Ex. 450, Campbell Opening Statement at 1.
674 Ex. 141, Lindell Opening Statement at 2.
675 Ex. 141, Lindell Opening Statement at 2; Tr. Vol. 3 at 194-195 (Lindell).
676 Ex 58, Mills Direct at 54.

due to a bowed rotor, which occurred when the rotor was removed from its turning gear while hot due to human error.[677]

409. Since the outage was the result of human error, XLI proposed disallowing investment of $24,104 and operating costs of $1.838 million.[678]

410. The Company pointed out that the $1.838 million of additional operating costs were incurred in 2013 and that these costs were not included in the 2014 test year.[679]The Company clarified that the $24,104 of capital addition is merely embedded within the rate base for the 2014 test year since that capital addition was incurred during the 2012-2013 outage.[680] As a result, the Company argued "[r]eopening NSP's past rate cases to readjust rates to account for [XLI's proposed disallowance] would violate the long-standing and well-supported Commission policy against retroactive ratemaking."[681]

411. XLI's proposed adjustment relates to both O&M costs as well as capital costs. Even though these costs are of a different nature, the Commission's standard to determine if inclusion of these costs in rates is just and reasonable is the same: prudence.[682] The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all relevant circumstances.[683]

412. The Company urged that its conduct should be reviewed based on its response to any human error that occurred. With respect to Black Dog 5/2, since the

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677 Ex. 58, Mills Direct at 54.
678 Ex. 260, Pollack Direct at 24.
679 Ex. 90, Heuer Rebuttal at 35.
680 Ex. 60, Mills Rebuttal at 17.
681 *In the Matter of Northern States Power Company's Petition for Deferred Accounting Treatment for Settlement Payments from SMMPA*, ORDER ALLOWING WITHDRAWAL OF PETITION, Docket No. E-002/M-96-1623 (Sept. 17 1997).
682 *In the Matter of the Petition of Northern States Power Company for Authority to Change Its Schedule of Gas Rates for Retail Customers Within the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER, Docket No. E-002/GR-85-108, 73 P.U.R.4th 395 (Dec. 30, 1985) ("[t]he standard for allowing recovery of a utility expense is that it is reasonable and prudent and related to the provision of the utility service").
683 *See* Charles F. Philips, Jr., THE REGULATION OF PUBLIC UTILITIES – THEORY AND PRACTICE at 292 (Public Utility Reports 1988); *see also* David J. Muchow, William A. Mogel, ENERGY LAW AND TRANSACTIONS at § 4.02[3][b] (2009).

Units came back on-line, "the plant has been operating well, and all of our performance indicators are improving and positive."[684] In fact, "[t]he project year-end equivalent availability factor…for 2014 is better than the previous 12 years."[685] The Company stated that its response to an unfortunate human error event resulted in improved performance based on the Company's prudent management of the plant.[686]

413. XLI's recommended disallowance imposes a standard of perfection, not prudence, on the Company and constitutes in retroactive ratemaking. Consequently, XLI's proposed adjustment for the 2012-2013 outage at Black Dog 5/2 should not be adopted.

414. Further, XLI recommended that any replacement fuel costs should also be disallowed in the AAA proceeding.[687] The Company stated that the AAA proceeding is the appropriate forum to address replacement power costs for this outage and the Sherco 3 outage.[688]

M. Capital Structure and Cost of Debt (2014 and 2015 Step) (Issue # 12)

415. One of the components in determining the rate of return for the Company is the capital structure, *i.e.*, whether the Company's proportion of long-term debt, short-term debt, preferred stock and common equity is reasonable. A related component is the cost of the short-term debt and of the long-term debt.

1. Capital Structure

416. A utility's capital structure provides the long-term structural foundation for the financing necessary to support its operations and capital investments.[689] The Commission generally uses a reasonableness standard to evaluate a utility's capital structure.[690] The Commission considers how a utility's debt and equity ratios

[684] Ex. 60, Mills Rebuttal at 16.
[685] Ex. 60, Mills Rebuttal at 16.
[686] Ex. 60, Mills Rebuttal at 18.
[687] Ex. 260, Pollack Direct at 24.
[688] Ex. 100, Clark Rebuttal at 44.
[689] Ex. 30, Tyson Direct at 7.
[690] Ex. 30, Tyson Direct at 7-8.

compare to those of similarly situated utilities; whether the utility's capital structure is an actual capital structure based on market forces or is instead an internal accounting structure; whether the utility's capital structure supports long-term credit quality; and whether the utility's capital structure provides long-term cost benefits to customers.[691]

417. The Company initially proposed a capital structure for the 2014 test year of 52.50 percent common equity, 45.61 percent long-term debt, and 1.89 percent short-term debt, and for Step year 2015 of 52.50 percent common equity, 45.63 percent long-term debt, and 1.87 percent short-term debt.[692] The Department agreed that this capital structure was appropriate and reasonable, subject to the caveat that the capital structure calculations should be updated in the Company's rebuttal testimony.[693]

418. In Rebuttal Testimony, the Company proposed the following capital structure based on updated calculations: for the 2014 test year, 52.50 percent common equity, 45.60 percent long-term debt, and 1.90 percent short-term debt; and for Step year 2015, 52.50 percent common equity, 45.61 percent long-term debt, and 1.89 percent short-term debt.[694] This updated proposed capital structure is very close to the originally proposed capital structure. The Department agreed that this updated proposed capital structure was appropriate and reasonable.[695]

419. The Company's proposed capital structure is reasonable. First, the Company's capital structure is consistent with the capital structures of other utilities, both at the operating company level as analyzed by Mr. Hevert,[696] and at the parent company level as analyzed by Dr. Amit.[697] To the extent that the Company's equity ratio is slightly higher than the averages of the groups analyzed, that is justified by the

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691 Ex. 30, Tyson Direct at 8; Ex. 400, Amit Direct at 44-45.
692 Ex. 30, Tyson Direct at 4.
693 Ex. 400, Amit Direct at 46-47, 51.
694 Ex. 31, Tyson Rebuttal at Schedules 3 and 7.
695 Ex. 403, Amit Surrebuttal at 10; Ex. 443, Amit Opening Statement at 4.
696 Ex. 27, Hevert Direct at 53-54 and Schedule 11.
697 Ex. 400, Amit Direct at 48; Ex. 28, Hevert Rebuttal at 9-17.

Company's significant capital expenditures of approximately $7.6 billion in its combined gas and electric utility business from 2005 to 2012.[698]

420. Second, NSPM's capital structure is an actual and market-based capital structure.[699] NSPM is a legally separate Minnesota corporation, issues its own debt securities, reports its capital structure in its own separate SEC filings, and credit ratings agencies assign credit ratings to NSPM as its own corporate entity.[700]

421. Third, when issuing long-term debt and targeting an equity ratio, the Company properly considers credit rating evaluations, its anticipated capital investments, the long-term stability of the capital structure in relation to the long life of its assets, the macroeconomic outlook, and the need to manage the maturities of long-term debt.[701]

422. Fourth, the Company's proposed capital structure has an effect on its financial integrity, which in turn benefits customers.[702] The Company's capital structure has allowed it simultaneously finance its considerable capital investments, achieve upgrades of its credit ratings, and reduce its cost of long-term debt.[703] The resulting financial strength ensures that the Company has consistent access to capital markets that will enable it to raise the future capital required to complete its capital investment plan.[704]

423. Finally, the components of the proposed capital structure (long-term debt, short-term debt, and common equity capital) were each calculated in a manner consistent with how those components were calculated in the Company's previous rate case.[705] Not only is the methodology consistent, but the actual capital structure

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[698] Ex. 31, Tyson Rebuttal at 9.
[699] Ex. 30, Tyson Direct at 9; Ex. 400, Amit Direct at 45; Ex. 31, Tyson Rebuttal at 5.
[700] Ex. 30, Tyson Direct at 9; Ex. 400, Amit Direct at 45.
[701] Ex. 30, Tyson Direct at 9-12; Ex. 31, Tyson Rebuttal at 6-8.
[702] Ex. 30, Tyson Direct at 13; Ex. 31, Tyson Rebuttal at 5-6, 9-10.
[703] Ex. 30, Tyson Direct at 13.
[704] Ex. 30, Tyson Direct at 13; Ex. 31, Tyson Rebuttal at 9.
[705] Ex. 400, Amit Direct at 46-47; Ex. 30, Tyson Direct at 27-30, 34-38.

the Company proposed for 2014 is very similar to the capital structure of 52.56 percent equity, 45.30 percent long-term debt, and 2.14 percent short-term debt approved by the Commission in the prior rate case.[706]

424. The ICI Group recommended that the Commission limit the amount of common equity that the Company could include in its capital structure to the amount of common equity employed by Xcel Energy, Inc as projected by Value Line: 47.5 percent in 2014 and 49.0 percent in 2015.[707]

425. This recommendation should not be adopted, because it fails to recognize that the Company's capital structure is separate from that of its parent company, Xcel Energy, Inc.[708]

426. Mr. Glahn testified on behalf of the ICI Group that the Company is nothing but an "accounting fiction, an entry on the books of Xcel Energy."[709] His testimony is incorrect, because the Company reports its actual capital structure in its own SEC filings and because S&P, Moody's, and Fitch assign credit ratings to the Company and to each of the Company's bonds.[710]

427. Utility operating companies, not holding companies, are the appropriate basis by which to analyze capital structure.[711] The Company does not finance its capital investments based on Value Line's projections, and Value Line does not include short-term debt in its projections.[712]

428. Modifying the Company's equity ratio, as the ICI Group recommended, would be seen as a significant adverse change in the Company's regulatory

[706] Ex. 30, Tyson Direct at 27.
[707] Ex. 250, Glahn Direct at 26.
[708] Ex. 402, Amit Rebuttal at 14-15.
[709] Ex. 251, Glahn Surrebuttal at 6.
[710] Ex. 31, Tyson Rebuttal at 5.
[711] Ex. 28, Hevert Rebuttal at 42.
[712] Ex. 28, Hevert Rebuttal at 42.

environment and thus would likely lead to a change in the credit outlook for the Company, potentially resulting in a credit downgrade.[713]

429. The Company's proposed capital structure of 52.50 percent common equity, 45.60 percent long-term debt, and 1.90 percent short-term debt for the 2014 test year, and 52.50 percent common equity, 45.61 percent long-term debt, and 1.89 percent short-term debt for Step year 2015, is reasonable and appropriate.

2. Cost of Debt

430. The Company initially recommended that for the 2014 test year, its cost of short-term debt should be 0.67 percent and its cost of long-term debt should be 4.93 percent, and for the 2015 Step year, its cost of short-term debt should be 1.12 percent and its cost of long-term debt should be 4.97 percent.[714]

431. In Rebuttal Testimony, the Company updated its cost of debt, resulting in a final recommendation that for the 2014 test year, the cost of short-term debt should be 0.62 percent and the cost of long-term debt should be 4.90 percent, and for the 2015 Step year, the cost of short-term debt should be 1.12 percent and the cost of long-term debt should be 4.94 percent.[715]

432. The Company's proposed cost of long-term debt for 2014 is lower than in the previous rate case, and is much lower than the 6.09 percent cost in Docket E-002/GR-10-971.[716]

433. The cost of long-term debt was calculated based on the coupon rate on all of the Company's bonds expected to be outstanding for each month of 2014, plus related expenses such as amortization expense for debt issuance costs, discounts or

[713] Ex. 31, Tyson Rebuttal at 11.
[714] Ex. 30, Tyson Direct at 4.
[715] Ex. 31, Tyson Rebuttal at 26-27 and 29, and Schedules 3 and 7.
[716] Ex. 30, Tyson Direct at 5.

premiums, and losses on reacquired debt.[717] This calculation methodology is consistent with the calculations of the cost of long-term debt in prior rate cases.[718]

434. The cost of short-term debt includes the interest expense for commercial paper and the monthly financing fees associated with maintaining a credit facility to provide back-up liquidity.[719]

435. The Department agreed with the Company's proposed cost of debt.[720] No other party commented on the cost of debt.

3. Rate of Return

436. The overall rate of return (ROR) reflects the common equity, LTD, and STD in the capital structure along with the costs of common equity, LTD and STD. The Company proposes a 7.62 percent ROR for 2014 test year and a 7.65 percent ROR for the 2015 Step.[721]

N. FERC Cost Comparison Study – KPI Benchmarks (Issue #70)

437. The Company conducts an annual Electric FERC Cost Comparison Study (Benchmarking Study) which compares Xcel Energy and its four operating companies to peer companies, investor-owned utilities in the Edison Electric Institute (EEI) Index.[722] The Study focuses on retail revenues, fuel and purchased power costs, and non-fuel O&M costs including Production, Transmission, Distribution, Customer Care, and Administrative & General.[723]

438. MCC recommended that in the instances where NSPM appears in the bottom two quartiles of any metric in the 2013 Benchmarking Study, the Company use those measures as key performance indicators to help improve the efficiency of

[717] Ex. 30, Tyson Direct at 28, 36.
[718] Ex. 30, Tyson Direct at 28, 36.
[719] Ex. 30, Tyson Direct at 30-31, 37.
[720] Ex. 400, Amit Direct at 52; Ex. 403, Amit Surrebuttal at 10.
[721] Ex. 31, Tyson Rebuttal at 27-28; Ex. 116 Tyson Opening Statement at 1-2.
[722] Ex. 67, Kline Rebuttal at 37.
[723] Ex. 100, Clark Rebuttal at 45.

Xcel Energy's operations.[724] In the 2013 Benchmarking Study, NSPM is trending below its peer companies with respect to (i) non-fuel O&M benchmarks (percent of retail revenue by total, per customer, per retail MWh sales, and per MWh generated) and (ii) transmission O&M benchmarks (transmission O&M per line mile and transmission O&M per MWh throughput).[725]

439. The Department agreed with MCC's recommendation to use benchmarks from the Benchmarking Study to improve the efficiency of the Company's operations.[726]

440. For non-fuel O&M costs, the Company has already implemented a KPI related to non-fuel O&M growth management for 2014.[727] The Company noted that unlike the Benchmarking Study, this KPI is tied to recoverable costs and takes into account the variation that may occur between cost categories and thus appropriately addresses O&M growth.[728]

441. With respect to the transmission O&M benchmarks, the Company pointed out that five of the top ten utilities with the lowest transmission O&M costs per MWh throughput have sold the vast majority of their transmission assets to a transmission company.[729] Higher ranking utilities have large retail loads and high MWh throughput but very small transmission systems and low O&M costs. Such factors have a large impact on their high ranking.[730] Conversely, the utilities in the bottom two quartiles tend to be large transmission-owning utilities that are members of a Regional Transmission Organization (RTO).[731] The MWh throughput calculations in the 2013 Benchmarking Study fail to capture the increased throughput

[724] Ex. 343, Maini Direct at 43-45.
[725] Ex. 343, Maini Direct at 43-44.
[726] Ex. 412, Ouanes Rebuttal at 16.
[727] Ex. 100, Clark Rebuttal at 46.
[728] Ex. 100, Clark Rebuttal at 46.
[729] Ex. 67, Kline Rebuttal at 40-41.
[730] Ex. 67, Kline Rebuttal at 40-41.
[731] Ex. 67, Kline Rebuttal at 40-41.

associated with the wheeling of power for others when an RTO member's transmission system is controlled and coordinated by the RTO due to the regional sharing of the transmission systems within the RTO.[732]

442. With respect to the transmission O&M line-mile calculation, utilities that have high transmission O&M costs per transmission line mile often provide service in some of the largest cities in the United States.[733] Transmission lines in very large cities tend to be underground or in areas that are difficult to access for maintenance. Customer density (the number of customers per mile) is also higher.[734] Both factors will increase transmission O&M costs per line mile.[735]

443. The 2013 Benchmarking Study does not control for comparability of data, different tracking and reporting systems, relative size of a utility's transmission system, or other variations among utilities and as a result it is not appropriate to use the study's non-fuel and transmission O&M benchmarks as KPIs.

O. Transmission Business Area Cost Controls (Issue #69)

444. MCC raised concerns about cost controls for the transmission business unit.[736] MCC recommended that each transmission project requiring a certificate of need should have a firm cost cap which cannot be exceeded for ratemaking purposes without Commission approval.[737]

445. The Company argued that a firm cost cap for transmission projects based on the cost estimates provided at the certificate of need stage is inappropriate. The Company pointed out that at the certificate of need stage there are a significant number of uncertainties that can impact the final cost of a project that will not be resolved until the final route is determined.[738]

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[732] Ex. 67, Kline Rebuttal at 40-41.
[733] Ex. 67, Kline Rebuttal at 41.
[734] Ex. 67, Kline Rebuttal at 41.
[735] Ex. 67, Kline Rebuttal at 41.
[736] Ex. 340, Schedin Direct at 15-21.
[737] Ex. 340, Schedin Direct at 17.
[738] Ex. 67, Kline Rebuttal at 20-29.

446. In addition, imposing a cost cap based on certificate of need cost estimates is inconsistent with the purpose of the certificate of need proceeding which is to determine system needs and the most appropriate way to meet that need through a comparison of reasonable alternatives.[739]

447. The Company also noted that there are ample opportunities for parties to review and challenge the prudence of transmission project costs. For certificate of need projects, parties can challenge prudence during rate case proceedings or in the Transmission Cost Recovery Rider.

448. For projects that do not require a certificate of need, MCC recommended that the Company and other MISO transmission owners set up a reasonable cost control mechanism at MISO that would be approved by FERC.[740]

449. The Company stated that processes are already in place at MISO to control costs. The Company pointed out that MISO and interested stakeholders have the power under the MISO tariff and the formula rate protocols to request, review and monitor transmission owner cost data.[741] This provides our stakeholders an opportunity to challenge the Company's transmission costs.[742] Second, MISO has a robust stakeholder process in which many entities actively participate.[743] Through this process, employees from the Company participated in MISO's regional planning effort o ensure that transmission expansion plans are fully vetted and appropriately sized.[744] The Company also noted that MISO is likely to develop additional cost control mechanisms in light of FERC Order No. 1000 but that development of these additional mechanisms may take time.[745]

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[739] Ex. 67, Kline Rebuttal 19.
[740] Ex. 340, Schedin Direct at 17.
[741] Ex. 67, Kline Direct at 36.
[742] Ex. 67, Kline Direct at 36.
[743] Ex. 67, Kline Direct at 36.
[744] Ex. 67, Kline Direct at 36.
[745] Ex. 67, Kline Direct at 36.

450. The Company has demonstrated that its transmission business unit has rigorous cost controls in place and that relevant personnel are held accountable for bringing transmission projects on time and on budget.

P. MYRP in General (Issue #79)

451. The ICI Group opposed the Company's MYRP proposal for several reasons: (1) the 2015 Step will get less scrutiny and lower-level review than a regular one-year rate case; (2) the 2015 Step will move the Company from regulatory lag to regulatory lead and may allow the Company to over-earn if the U.S. economy improves; (3) the inclusion of only Company-selected items in the 2015 Step tilts the playing field against customers who will not have access to the Company's entire 2015 financial data; and (4) the process and reporting requirements for setting the 2015 Step rates are extremely complicated.[746]

452. The ICI Group believed that even with the risk of annual, consecutive rate cases, customers benefit from the transparency of having all revenue and expenses examined at one time in one proceeding.[747] The ICI Group recommended that the Company's MYRP will be denied and the rates set in this proceeding based on 2014 test year costs and assets.[748]

453. The Company opposed the ICI Group's recommendation and urged the Commission to accept the MYRP as proposed and modified by the Company during this proceeding.

454. The Company stated that it proposed a MYRP as the best regulatory fit to reflect the current environment of significant investments the Company is undertaking to support its ability to provide reliable and safe electric service to its customers.[749]

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746 Ex. 250, Glahn Direct at 6-9.
747 Ex. 250, Glahn Direct at 6-9.
748 Ex. 250, Glahn Direct at 6-9.
749 Ex. 100, Clark Rebuttal at 4.

455. The Company noted that the MYRP offers several benefits to stakeholders including: greater rate predictability for customers, opportunities for rate moderation, regulatory efficiency, and long-term view of Company financials.[750] The Company noted that MYRP provides additional benefits for customers, because the 2015 Step does not reflect the Company's full revenue requirement for 2015.[751]

456. The Company believes that MYRP will also provide benefits into 2016, as long as it is implemented in a manner that balances the interests of all Company stakeholders.[752]

IV. RATE DESIGN AND CLASS COST OF SERVICE STUDY

A. Background

457. Rate design occurs after the Commission establishes the Company's revenue requirement. The rate design process is a zero-sum game: a reduction in one rate necessarily results in an equal and offsetting increase in one or more other rates.[753]

458. Under Minnesota law, the rates that result from the rate design process must be just and reasonable and may not be unreasonably preferential, unreasonably prejudicial, or discriminatory.[754] Rates design must also consider issues of conservation and affordability.[755] Balancing these factors in the rate design process is a quasi-legislative function that largely rests on policy determinations.[756]

459. The Commission considers a variety of factors when designing rates, including: "economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; ability to bear,

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750 Ex. 100, Clark Rebuttal at 4-5.
751 Ex. 100, Clark Rebuttal at 4-5.
752 Ex. 100, Clark Rebuttal at 4-5.
753 Company Initial Brief at 124.
754 Minn. Stat. § 216B.03.
755 Minn. Stat. §§ 216B.03, 216B.2401, 216B.16, subd. 15.
756 *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n*, 312 Minn. 250, 260, 251 N.W. 2d 350, 357 (1977).

deflect, or otherwise compensate for additional costs; and in particular, the cost of service."[757]

460. The Company uses similar principals when designing rates:

- Produce total revenue equal to test year revenue requirements, thereby providing the Company a reasonable opportunity to earn its authorized return on investment;

- Accurately reflect the resource costs of providing service and, where appropriate, the market value of the service;

- Provide sufficient flexibility in pricing levels and provisions for our electric service to remain competitive in the broader energy market; and

- Provide reasonable pricing by considering the importance of rate continuity, customer understanding, revenue stability, and administrative practicality.[758]

B. Class Cost of Service Study (Issue #51)

461. The Class Cost of Service Study (CCOSS) allocates jurisdictional costs to customer classes using class cost allocation factors. The CCOSS measures the contribution each class makes to the Company's overall cost of service, including calculating inter-class and intra-class cost responsibilities.[759]

462. The Company filed 2014 and 2015 CCOSSs with its Application, as required by Commission Rules and the Commission's Order Establishing Terms, Conditions and procedures for multiyear rate plans in Docket No. E,G999/M-12-587.[760]

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[757] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* FINDINGS OF FACT, CONCLUSIONS AND ORDER at 14, Docket No. E002/GR-10-971 (May 14, 2012) (hereinafter E002/GR-10-971 ORDER).

[758] Ex. 105, Huso Direct at 4-5.

[759] Ex. 102, Peppin Direct at 1-2.

[760] Minn. R. 7825.4300; *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19*, Docket No. E,G999/M-12-587, ORDER ESTABLISHING TERMS, CONDITIONS AND

463. The Company revised the 2014 and 2015 CCOSSs in its Rebuttal Testimony to reflect: 1) the Company's Rebuttal revenue requirement; 2) Rebuttal sales and customer forecasts; 3) removal of the Conservation Improvement Program (CIP) Conservation Cost Recovery Charge (CCRC) from the CCOSSs, as recommended by the Department; 4) a reduction in the amount of economic development discounts to actual 2013 levels, as recommended by the Department; and 5) and using actual replacement cost data for Pleasant Valley and Borders in the 2015 CCOSS.[761]

464. The Company's proposed CCOSS incorporates many of the fundamental aspects of previous CCOSSs, including using the Plant Stratification method to classify and allocate fixed production plant and the class definitions used in previous cases.[762] These two aspects of the CCOSS have been used by the Company with Commission approval for several rate cases.[763] The Company's proposed CCOSSs also include two changes approved by the Commission in the Company's 2013 rate case (Docket No. E002/GR-12-961): 1) allocation of capacity-related fixed production plant and transmission plant to classes based on the summer peak; and 2) allocation of economic development discounts to all classes.[764]

465. The Department, OAG, MCC and XLI have all presented different CCOSSs in this case and have taken a variety of positions on CCOSS-related issues.

1. CCOSS Methodology

466. The Company explained that it performs a critical analysis of its CCOSS prior to filing each rate case.[765] According to the Company, these analyses are

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PROCEDURES FOR MULTIYEAR RATE PLANS at Order Point 18 (June 17, 2013). *See* Ex. 13, Vol. 3 (Required Information).

761 Ex. 103, Peppin Rebuttal at 2-3.

762 Ex. 102, Peppin Direct at 11-12.

763 Ex. 102, Peppin Direct at 11-12. *See also In the Matter of the Application of Northern States Power Company for an Increase in its Minnesota Electric Retail Rates*, FINDINGS OF FACT CONCLUSIONS OF LAW AND ORDER at 83-87, Docket E001/GR-92-1185 (Sept. 29, 1993).

764 Ex. 102, Peppin Direct at 11.

765 Ex. 102, Peppin Direct at 11-12; Ex. 103, Peppin Rebuttal at 18.

informed by the outcomes of previous cases, new or renewed studies and changes that have occurred in the Company's business that are relevant to the cost-measurement process.[766] The Company contends that these refinements improve the measurement of cost causation.[767]

467. The Company made five refinements to its CCOSS methodology in this case: 1) classification and allocation of Other Production O&M; 2) classification and allocation of Company-owned wind; 3) separation of distribution lines costs into single-phase and multi-phase categories; 4) direct assignment of costs to the Lighting class; and 5) removal of CIP CCRC costs and revenues from the CCOSS.[768] The refinements related to Other Production O&M and Company-owned wind are contested in this case.

2. Other Production O&M

468. Other Production O&M costs are production plant operations and maintenance expenses "other" than fuel and purchased power.[769]

469. As part of the 2013 rate case, the Commission ordered the Company to perform an analysis of Other Production O&M costs in this case, stating:

> In the initial filing of its next rate case, Xcel shall refine its Class Cost of Service Study cost allocation method by identifying any and all Other Production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, while allocating the remainder of Other Production O&M costs on the basis of the Production Plant.[770]

[766] Ex. 102, Peppin Direct at 11-12.
[767] Ex. 104, Peppin Surrebuttal at 6-7.
[768] Ex. 102, Peppin Direct at 11, Table 4; Ex. 103, Peppin Rebuttal at 2.
[769] Company Initial Brief at 126.
[770] 2013 RATE CASE ORDER at Order Point 49.

470. In response, the Company examined each of the 117 cost items that make up Other Production O&M.[771] The Company identified chemicals and water use as being costs that vary directly with the amount of energy produced.[772]

471. The Company prepared a compliance CCOSS that classified chemicals and water use costs as energy-related and classified the remaining Other Production O&M costs based on the type of production plant associated with the costs.[773]

472. Using underlying plant type to classify the Other Production O&M costs that do not vary directly with energy output is known as the "location method."[774] The location method is one of the methodologies identified in the National Association of Regulatory Commissioners Electric Utility Cost Allocation Manual (NARUC Manual) used to classify Other Production O&M costs that do not vary directly with energy output.[775] One of the other methodologies identified in the NARUC Manual is known as the "predominant nature" method.[776] Under the predominant nature method, Other Production O&M costs that do not vary directly with energy output are classified "according to [their] 'predominant' – i.e. [capacity]-related or energy-related – character."[777] The two methods result in different energy-related and capacity-related classifications of Other Production O&M costs.

Table 1
Comparison of Other Production O&M Cost Classification Methodologies[778]

Classification Methodology	Capacity-Related	Energy-Related
Location Method	35.0%	65.0%
Predominant Nature Method	78.4%	21.6%

[771] Ex. 102, Peppin Direct at 19 and Schedule 7.
[772] Ex. 102, Peppin Direct at 19-20.
[773] Ex. 102, Peppin Direct at 20 and Schedule 8; Ex. 103, Peppin Rebuttal at 23-25.
[774] Ex. 102, Peppin Direct at 22; Ex. 103, Peppin Rebuttal (quoting National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992)).
[775] Ex. 103, Peppin Rebuttal (quoting National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992)).
[776] Ex. 102, Peppin Direct at 22.
[777] Ex. 102, Peppin Direct at 22 (citing National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992)).
[778] Ex. 102, Peppin Direct at 24, Table 10.

473. The Company's proposed CCOSSs are based on the predominant nature method. The Company asserted the predominant nature method is superior to the locational method because it is based on an individualized analysis of each cost category and does not rely on plant-type as a proxy for determining the nature of each cost type.[779] According to the Company, using proxies produces a less refined view of the nature of Other Production O&M costs.[780] For example, the Company stated that under the location method, all non-chemicals and non-water Other Production O&M that occurs at peaking plants is treated as capacity-related, even though some of those costs clearly change with the amount of energy produced.[781] The Company also supported the predominant nature method because it is characterized as a "common method" in the NARUC Manual while the location method is deemed "not standard practice".[782]

474. The MCC and XLI supported the use of the predominant nature method.[783]

475. Both the Department and OAG recommend using the location method to classify and allocate Other Production O&M costs that do not vary directly with energy output.[784] Their opposition to the predominant nature method was based upon: 1) the Company's position in previous rate cases; 2) a view that the Commission required use of the location method in this case; and 3) their conclusion that the location method results in reasonable classifications.[785]

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779 Ex. 103, Peppin Rebuttal at 26.
780 Ex. 103, Peppin Rebuttal at 26.
781 Ex. 103, Peppin Rebuttal at 27; Company Initial Brief at 128.
782 Ex. 103, Peppin Rebuttal at 25-26.
783 Ex. 343, Maini Direct at 24-25; Ex. 345, Maini Surrebuttal at 17-18; Ex. 262, Pollock Rebuttal at 16-23.
784 Ex. 408, Ouanes Direct at 35; Ex. 377 Nelson Rebuttal at 18.
785 Ex. 408, Ouanes Direct at 29-34; Ex. 414, Ouanes Surrebuttal at 7-8; Ex. 377, Nelson Rebuttal at 14-18.

476. The Company and XLI explained that it is common to refine CCOSS methodologies based on new or better information.[786] In this case, the Company stated its evaluation of the 117 different cost items that make up Other Production O&M was a new analysis not previously performed in past cases.[787] Therefore, the Company and XLI concluded the Company's decision to refine its methodology based on new information to be both reasonable and consistent with past practice.[788]

477. The Company and XLI also pointed out that Company's evaluation of different methodologies for classifying Other Production O&M costs was consistent with the broader intent expressed in the Commission's Order in the 2013 rate case.[789] Finally, the Company, XLI and MCC all asserted the detailed examination conducted under the predominant nature method results in more accurate reflection of cost-causation than occurs under the proxy-based location method.[790]

478. Parties appear to agree with the Company's classification of chemicals and water use as being energy-related;[791] this classification is reasonable and should be adopted.

479. The Company's use of the predominant nature method in its proposed CCOSSs is reasonable. The predominant nature method is a refinement of past practice supported by a new analysis. The Company's examination of each of the 117 cost items that make up Other Production O&M avoids the need to rely on proxies in the classification process. The method is also considered "common" practice, while the locational method is "not standard."[792] The Company's proposal is therefore reasonable and should be adopted.

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786 Ex. 104, Peppin Surrebuttal at 6-8; Ex. 262, Pollock Rebuttal at 19.
787 Ex. 104, Peppin Surrebuttal at 8-9.
788 Ex. 103, Peppin Rebuttal at 27; Ex. 262, Pollock Rebuttal at 18-19.
789 Ex. 102, Peppin Direct at 25; Ex. 262, Pollock Rebuttal at 18.
790 Ex. 103, Peppin Rebuttal at 27-28; Ex. 343, Maini Direct at 24-25; Ex. 262, Pollock Rebuttal at 21.
791 Ex. 408, Ouanes Direct at 35; Ex. 377 Nelson Rebuttal at 18; Ex. 343, Maini Direct at 25; Ex. 262, Pollock Rebuttal at 16-23; Tr. Vol. 4 at 100-101 (Ouanes).
792 Ex. 103, Peppin Rebuttal at 25 (quoting page 66 of the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual (Jan. 1992)).

3. Customer-Related Distribution Costs

480. The cost of primary lines, secondary lines, secondary transformers and service drops are classified as both demand-related and customer-related costs in the Company's CCOSS.[793] The Commission has explained this classification process as follows:

> Utility distribution plant is installed to extend service to customers and to meet their peak demand requirements. Because this distribution plant serves two purposes, total distribution costs are classified as both customer and demand-related. Imputing a minimum distribution system is a common method for deriving this breakdown. If utilities were concerned with only extending service to customers and meeting their minimum requirements, they would install the smallest possible distribution system. The cost of installing this theoretical minimum system is then classified as customer-related, while remaining distribution costs are classified as demand-related.[794]

481. The Company separates distribution costs into demand-related and customer-related components using the Minimum Distribution System (MDS) method. The Company has used this method in each of its electric rate cases since at least 1985.[795]

482. The OAG recommended a 10 percent adjustment to the Company's classification of distribution costs.[796] The OAG asserted the adjustment is appropriate because the MDS method overestimates customer-related costs and that

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793 Ex. 103, Peppin Rebuttal at 28-29.

794 *In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 74, Docket No. E002/GR-91-1 (Nov. 27, 1991).

795 Ex. 103, Peppin Rebuttal at 28. *See also In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Utility Service for Customers within the State of Minnesota*, ORDER at 28, Docket No. E002/GR-85-558 (June 2, 1986)(indicating the Company's CCOSS was performed using the MDS method)(*hereinafter* E002/GR-85-558 ORDER).

796 Ex. 378, Nelson Surrebuttal at 10; Ex. 142, Nelson Opening Statement at 1.

the zero-intercept method is superior.[797] The OAG also contended an adjustment is appropriate because there is smaller equipment installed on the Company's system and because the Company does not have the original cost data used to develop the assumptions supporting its minimum system study.[798]

483. The Company maintained that its classification of distribution related costs into customer-related and capacity-related components is reasonable for use in this case.[799] According to the Company, both the MDS method and the zero-intercept method are accepted practice.[800] Further, the Company stated the OAG's position that the MDS method overestimates the customer-related portion of distribution costs was not supported in the record.[801] Finally, the Company pointed out that the Commission has identified the MDS method as a "common method" for separating distribution costs into demand-related and customer-related components and has approved or required use of the MDS method for all Minnesota electric utilities.[802]

484. The Company also disagreed that the other reasons cited by the OAG justify an adjustment. The Company explained that the minimum sized equipment used in its minimum system study was established in preparation for the Company's

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797 Ex. 375, Nelson Direct at 16.
798 Ex. 378, Nelson Surrebuttal at 10; Ex. 142, Nelson Opening Statement at 1.
799 Ex. 103, Peppin Rebuttal at 36-37; Company Initial Brief at 131.
800 Ex. 103, Peppin Rebuttal at 29-31; Company Initial Brief at 130 (citing Ex. 143, Excerpts from the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual at 9 (page 90 of the manual)).
801 Company Initial Brief at 130.
802 Ex. 103, Peppin Rebuttal at 29-30; Xcel Energy Initial Brief at 130 (citing *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION at ¶ 481, Docket No. E017/GR-10-239 (Feb. 14, 2011)(adopted by FINDINGS OF FACT, CONCLUSIONS AND ORDER at 7 (Apr. 25, 2011)); *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS AND ORDER at Order Point 15.C., Docket No. E001/GR-10-276 (Aug. 12, 2011)(*hereinafter* E001/GR-10-276 ORDER); *In the Matter of the Application of Minnesota Power for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota*, Docket No. E015/GR-94-001, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 51 (Nov. 22, 1994)(indicating Minnesota Power performed a minimum distribution study and requiring further discussion of its methodology in the company's next rate case)).

1992 rate case based the minimum sized equipment being installed at that time.[803] According to the Company's distribution witness, the minimum sized equipment used in the study (based on 1992 standards) reasonably approximates the minimum size equipment being installed today, though some differences do exist.[804] For example, the current minimum sized poles and transformers are larger than what is used in the minimum system study, while the minimum sized single-phase primary underground conductor is smaller than what is used in the minimum system study.[805] All else being equal, the Company stated that the current minimum sized poles and transformers are more expensive than the equipment used in the minimum system study and the current minimum sized single-phase primary underground conductor is less expensive than what is used in the study.[806]

485. The Company concluded that focusing only the current equipment that is smaller than what is in the study and ignoring current equipment that is larger and more expensive than what is in the study leads to an arbitrary adjustment.[807]

486. Regarding the cost data used in the minimum system study, the Company explained that it escalated the original per unit installed cost of the minimum sized equipment using the Handy-Whitman construction cost index.[808] The Company said it used the escalation method because it does not track minimum sized distribution equipment on an installed cost basis.[809] The Company also stated that while it did not have the historical records need to replicate the development of the original per unit installed costs of the minimum sized equipment,[810] the per unit costs and escalation method used in this case were the same as what was used in the

[803] Ex. 70, Foss Rebuttal at 2-4.
[804] Ex. 70, Foss Rebuttal at 4.
[805] Ex. 70, Foss Rebuttal at 4-8.
[806] Ex. 70, Foss Rebuttal at 4-8.
[807] Company Initial Brief at 131.
[808] Ex. 103, Peppin Rebuttal at 33; Ex. 104, Peppin Surrebuttal at 5.
[809] Ex. 104, Peppin Surrebuttal at 5.
[810] Ex. 377 Nelson Rebuttal at Schedules REN-19 – REN-21.

Company last six rate cases.[811] Finally, the Company explained, and the OAG eventually acknowledged, that the Company appropriately accounts for the minimum load associated with the minimum sized system, which was another justification previously relied upon by the OAG.[812]

487. The Company separated demand related costs into customer-related and demand-related components using the same methodology as it has used in its past six rate cases. There is no evidence in the record supporting the contention that the MDS method automatically over-estimates customer-related costs. Further, the OAG's recommended adjustment is, by the OAG's own admission, arbitrary.[813] Arbitrarily changing a cost classification is not reasonable.[814] The Company's classification of distribution related costs into customer-related and capacity-related components is reasonable for use in this case.

488. Consistent with the OAG's recommendation and the Company's commitment, the Company should fully reexamine all of the assumptions supporting its minimum system study, including the engineering assumptions supporting the minimum sized equipment and the installed cost of the minimum sized equipment.[815] To the extent the Company is able to gather sufficient data, the Company should also include a zero-intercept analysis as part of the initial filing of its' next rate case.

4. Classification of Fixed Production Plant

489. The Company classifies fixed production plant into capacity-related and energy-related sub-functions using the Plant Stratification method.[816] Under this

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811 Ex. 104, Peppin Surrebuttal at 5.
812 Tr. Vol. 3 at 247-248 (Nelson); Ex. 375, Nelson Direct at 24-25.
813 Ex. 375, Nelson Direct at 26; Tr. Vol. 3 at 249-250 (Nelson).
814 E002/GR-85-558 ORDER at 28-29 ("The ALJ rejected the three modifications [to the Company's CCOSS] suggested by the RUD-AG. He rejected the minimum system adjustment because there is no indication in the record that the RUD-AG's proposed solution does anything but produce an arbitrary number for the amount of customer costs…. The Commission agrees in every respect with the findings of the ALJ regarding the class cost of service study and adopts his findings and supporting discussion as its own.")
815 Ex. 103, Peppin Rebuttal at 35; Ex. 104, Peppin Surrebuttal at 6; Ex. 375, Nelson Direct at 26.
816 Ex. 102, Peppin Direct at 12.

method, the capacity-related portion of fixed production plant is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant.[817] The percent of total generation costs that exceed the cost of a comparable peaking plant are classified as energy-related.[818]

490. The Company claimed the advantage of Plant Stratification is that it recognizes the duel benefits associated with baseload and intermediate generation resources.[819] For example, according to the Company, a significant portion of the fixed costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs associated with such plants, thereby minimizing total cost.[820] Plant Stratification assigns a portion of the cost of these plants to energy and a portion to capacity.[821]

491. The MCC requested that the Plant Stratification method be replaced by the Straight Fixed-Variable (SFV) method.[822] According to the MCC, fixed production plant is built to serve demand and reserve margin requirements and is therefore appropriately classified as capacity.[823] Under the MCC's SFV method, fuel and other variable costs associated with the throughput derived from fixed production plant investments are classified as energy-related.[824] MCC stated the move to the SFV method would be reasonable because it would send better price signals, would improve load factors and help address the addition of policy-based resources to the system.[825]

492. The Company stated the movement to the SFV method would be a significant departure from past precedent and would lead to a significant shift in inter-

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817 Ex. 102, Peppin Direct at 12.
818 Ex. 102, Peppin Direct at 12.
819 Ex. 102, Peppin Direct at 13-14; Ex. 103, Peppin Rebuttal at 10.
820 Ex. 102, Peppin Direct at 13-14.
821 Ex. 102, Peppin Direct at 12-13.
822 Ex. 343, Maini Direct at 19.
823 Ex. 343, Maini Direct at 17; Ex. 345, Maini Surrebuttal at 22.
824 Ex. 343, Maini Direct at 16-21.
825 Ex. 343, Maini Direct at 17-19; Ex. 345, Maini Surrebuttal at 12-13.

class cost responsibilities.[826] Also, the Company pointed out the SFV method does not reflect the dual nature of baseload and intermediate fixed production plant.[827]

493. As pointed out by the Commission in the Company's previous rate cases,[828] and in several other recent electric rate cases,[829] Plant Stratification recognizes baseload and intermediate generation resources provide both energy and capacity, and that a significant portion of the fixed costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs associated with such plants, thereby minimizing total cost. The continued use of the Plant Stratification methodology is therefore reasonable.

494. XLI did not challenge the use of the Plant Stratification method, but instead recommended modifying the Company's Plant Stratification analysis in two ways: 1) replace the current-dollar replacement value of a peaker with the estimated cost of a new peaking plant used by the Company to calculate the Windsource capacity credit and 2) replace current-dollar replacement costs for each plant type with depreciated replacement values.[830]

495. The Company, Department and OAG all opposed the XLI's recommended change to the Plant Stratification methodology.[831] The Company and Department asserted the XLI's stratification analysis was not performed on an apples-to-apples basis, but rather mixed depreciated and undepreciated costs.[832]

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826 Ex. 102, Peppin Direct at 11-12 (stating the Company has used Plant Stratification in its CCOSSs since the 1970's); Ex. 103, Peppin Rebuttal at 10 (identifying an approximately $19.8 million increase in Residential class cost responsibility under the SFV method). *See also* E001/GR-10-276 ORDER at 50; E017/GR-07-1178 ORDER at 69.

827 Ex. 103, Peppin Rebuttal at 10.

828 E002/GR-10-971 ORDER at 20; E002/GR-08-1065 ORDER at 44.

829 E001/GR-10-276 ORDER at 50; *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E017/GR-07-1178, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 69 (Aug. 1, 2008)(*hereinafter* E017/GR-07-1178 ORDER). Note that plant stratification is referred to as "the equivalent peaker methodology" in the Commission's ORDERS in Docket Nos. E001/GR-10-276 and E017/GR-07-1178.

830 Ex. 260, Pollock Direct at 33, 36.

831 Ex. 103, Peppin Rebuttal at 11-12; Ex. 412, Ouanes Rebuttal at 10-11; Ex. 377, Nelson Rebuttal at 7-10.

832 Ex. 103, Peppin Rebuttal at 11-12; Ex. 412, Ouanes Rebuttal at 10-11.

Table 2
Comparison of Plant Stratification Calculations[833]

Calculation	Company	XLI
Numerator	Current-Dollar CT Replacement Cost	Undepreciated Cost of New CT
Denominator	Current-Dollar Plant Type Replacement Cost	Depreciated Plant Type Replacement Cost

496. The Company and Department stated that when XLI's methodology is corrected to place the numerator and denominator on comparable grounds (by comparing the cost of a new peaker to the cost of new nuclear, fossil and other resources), more fixed production plant is classified as energy-related than is the case under the Company's Plant Stratification methodology.[834]

497. The OAG also showed that the XLI's methodology implies that as generation ages, it begins to meet customers' demand instead of their energy needs.[835]

498. The XLI's methodology is unreasonable and should not be adopted.

5. Company-Owned Wind

499. The Company's CCOSSs include four Company-Owned wind projects: Nobles, Grand Meadow, Borders and Pleasant Valley.[836] Nobles and Grand Meadow are included in both the 2014 and 2015 CCOSSs, while Pleasant Valley and Borders are included in the 2015 CCOSS.[837]

500. The Company classified Pleasant Valley and Borders into capacity-related and energy-related components using the Plant Stratification method, similar to other fixed production plant.[838] The Department and OAG agreed with this

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833 Company Initial Brief at 133.
834 Ex. 103, Peppin Rebuttal at 11-12; Ex. 412, Ouanes Rebuttal at 11.
835 Ex. 377 Nelson Rebuttal at 9.
836 Ex. 103, Peppin Rebuttal at 16.
837 Ex. 103, Peppin Rebuttal at 16.
838 Ex. 103, Peppin Rebuttal at 16.

treatment.[839] The MCC did not take a specific position on the classification and allocation of Pleasant Valley and Borders, but rather recommends these projects be recovered through riders.[840]

501. The Company classified Nobles and Grand Meadow as 100 percent capacity-related.[841] The Company asserted the projects should be treated differently from Pleasant Valley and Borders on grounds of cost causation.[842] According to the Company, Nobles and Grand Meadow were acquired to fulfill the Company's Renewable Energy Standard (RES) obligations,[843] while Borders and Pleasant Valley were acquired to minimize system costs, consistent with how other fixed production plant is added to the system.[844]

502. The Department and OAG did not support the Company's proposed treatment of Nobles and Grand Meadow. The Department recommends classifying all Company-owned wind, including Nobles and Grand Meadow, using the Plant

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839 Ex. 408, Ouanes Direct at 27; September 26, 2014 Letter from Ian Dobson, Assistant Attorney General to the Honorable Jeanne Cochran.

840 September 30, 2014 Letter from Richard J. Savelkoul to the Honorable Jeanne M. Cochran.

841 Ex. 103, Peppin Rebuttal at 16.

842 Ex. 102, Peppin Direct at 27; Ex. 103, Peppin Rebuttal at 17.

843 Ex. 102, Peppin Direct at 27-28; Ex. 103, Peppin Rebuttal at 17 and Schedule 5 (citing *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for the Grand Meadow Wind Farm*, Docket No. E002/CN-07-873, ORDER (Dec. 24, 2007); *In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, for Approval of Investments in Two Wind Power Projects: 200 MW Nobles Wind Project and 150 MW Merricourt Wind Project*, Docket No. E002/M-08-1437, ORDER APPROVING INVESTMENTS AND EXPENDITURES, FINDING THE NOBLES PROJECT EXEMPT FROM OBTAINING A CERTIFICATE OF NEED, AND ADDING REQUIREMENTS (June 10, 2009)).

844 Ex. 103, Peppin Rebuttal at 17 and Schedule 5 (citing *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 600 MW of Wind Generation*, Docket No. E002/M-603, *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 150 MW of Wind Generation*, Docket No. E002/M-13-716, ORDER APPROVING ACQUISITIONS WITH CONDITIONS at 9-10 (Dec. 13, 2013)("In the current dockets, Xcel acquired new facts when it received bids for new wind turbine projects demonstrating that wind power had become more competitive with other sources of electricity. And Xcel adapted. In brief, Xcel concluded that it could operate more efficiently by increasing its reliance on electricity from wind and reducing its reliance on electricity from other sources such as fossil fuels. And Xcel identified the best available new wind resources via a competitive bidding process. Xcel's filings support these assertions, and no party presented evidence challenging either assertion.")).

Stratification method;[845] the OAG recommended classifying Nobles and Grand Meadow as 100 percent energy related.[846]

503. Both the Department and OAG maintained the Company's proposed treatment of Nobles and Grand Meadow conflicted with its position in previous cases and past Commission treatment of the projects.[847] The Department also stated there are theoretical arguments against classifying any generation facility as 100 percent demand-related.[848]

504. The OAG asserted that its recommended treatment was appropriate because the Company's RES obligations are measured on an energy basis, not capacity.[849] The OAG also cited the NARUC manual for the proposition that capital costs that reduce fuel costs should be classified as energy-related and drew the conclusion that Nobles and Grand Meadow were added to reduce fuel consumption.[850]

505. The MCC recommended that all renewable investment be allocated using base revenues.[851] The MCC stated this method implicitly includes both energy and capacity elements and mimics existing rate design.[852]

506. The Company acknowledged that it had supported different classification methodologies for Nobles and Grand Meadow in the past, but asserted that the new information available in this case made the Company's proposed refinement reasonable.[853] Specifically, the Company stated there is a clear difference

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845 Ex. 408, Ouanes Direct at 27.
846 Ex. 375, Nelson Direct at 10. The OAG identifies plant stratification as "an acceptable method," though it supports a 100 percent energy classification as being most appropriate. Ex. 377, Nelson Rebuttal at 13.
847 Ex. 408, Ouanes Direct at 24-26; Ex. 377 Nelson Rebuttal at 11-13.
848 Ex. 408, Ouanes Direct at 22.
849 Ex. 375, Nelson Direct at 8.
850 Ex. 375, Nelson Direct at 9.
851 Ex. 343, Maini Direct at 23. The MCC did not take a specific position on the allocation of Pleasant Valley and Borders, but rather recommends these projects be recovered through riders. *See* September 30, 2014 Letter from Richard J. Savelkoul to the Honorable Jeanne M. Cochran.
852 Ex. 343, Maini Direct at 23.
853 Ex. 103, Peppin Rebuttal at 19-20.

between renewables that were added to minimize system costs (Pleasant Valley and Borders) and those added to fulfill RES obligations.[854] The Company and XLI both indicated that it is common to refine CCOSS methodologies in the face of new or better information.[855]

507. The Company disagreed with the Department's recommendation to apply the Plant Stratification methodology to Nobles and Grand Meadow.[856] According to the Company, Plant Stratification mirrors least-cost planning by recognizing a tradeoff between the lower-capital cost of peaking plants and the fuel savings achieved through intermediate and baseload plants.[857] The Company stated it did not engage in this tradeoff when pursuing Nobles and Grand Meadow, making the Plant Stratification method inappropriate.[858]

508. The Company also disagreed with the OAG's 100 percent energy classification.[859] The Company stated that Nobles and Grand Meadow were acquired to comply with the RES obligation, and that if the Company was only interested in procuring energy, it may have pursued other options.[860]

509. Finally, in response to both the Department and the OAG, the Company contended that the operational characteristics of Nobles and Grand Meadow were not relevant because the projects were not pursued for operational purposes.[861]

510. Pleasant Valley and Borders were added to minimize system costs on the same basis as other production plant. It is therefore reasonable to classify these projects using the Plant Stratification method.

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[854] Ex. 103, Peppin Rebuttal at 17-18.
[855] Ex. 104, Peppin Surrebuttal at 6-8; Ex. 262, Pollock Rebuttal at 19.
[856] Ex. 103, Peppin Rebuttal at 19.
[857] Ex. 103, Peppin Rebuttal at 19.
[858] Ex. 102, Peppin Direct at 27-28; Ex. 103, Peppin Rebuttal at 19.
[859] Ex. 103, Peppin Rebuttal at 19.
[860] Ex. 103, Peppin Rebuttal at 19.
[861] Ex. 103, Peppin Rebuttal at 18.

511. As for Nobles and Grand Meadow, there are four alternatives before the Commission:

Table 3
Percentage of Nobles and Grand Meadow Costs Allocated to Classes[862]

	Residential	C&I Non-Demand	C&I Demand	Lighting
OAG (100% Energy)	28.91%	3.29%	67.37%	0.43%
Department (Plant Stratification)	29.16%	3.31%	67.12%	0.41%
Company (100% Capacity)	34.52%	3.68%	61.80%	0.00%
MCC (Base Revenues)	39.22%	4.03%	55.57%	1.18%

512. Nobles and Grand Meadow were acquired on a different basis than Pleasant Valley and Borders, meaning a different classification method is appropriate.

513. The cost allocation under the Company's proposal reasonably reflects the policy nature of the Nobles and Grand Meadow projects and is reasonable overall; it should be adopted.

6. Calculation of the D10S Capacity Allocator

514. The D10S capacity allocator is calculated based on each class's load that is coincident with the NSP System peak, as measured by the forecasted test year class hourly load shapes.[863]

515. The OAG asserted the allocator should be calculated using each class's load at the hour of the MISO peak, not the Company's peak.[864]

516. The Company explained that the OAG's proposed calculation would require MISO to publish an hourly forecast that is compatible with the test year, which MISO currently does not do.[865] The Company also noted that there is no way

[862] Ex. 103, Peppin Rebuttal at 22.
[863] Ex. 103, Peppin Rebuttal at 37.
[864] Ex. 375, Nelson Direct at 13; Ex. 378, Nelson Surrebuttal at 13.
[865] Ex. 103, Peppin Rebuttal at 37-38.

of knowing how each class' share of the MISO peak differs from each class' share of the NSP system peak.[866]

517. The OAG responded that the MISO peak occurs earlier in the day than does the NSP peak and residential customers would represent a lower proportion of the MISO peak.[867]

518. XLI asserted that the NSP system peak was the key factor in determining resource need and that the OAG had provided no evidence supporting a different calculation.[868]

519. In order to calculate the D10S allocator based on the MISO peak, MISO would need to publish an hourly forecast that is compatible with the test year. MISO does not publish such a forecast, making the OAG's recommendation unfeasible.

7. Allocation of Economic Development Discounts

520. In the 2013 rate case, the Commission decided that all classes should share in the cost of economic development discounts, but ordered the Company to provide additional information in this case regarding the appropriate cost allocation.[869]

521. In response, the Company evaluated different allocation options in its Direct Testimony;[870] the Department and OAG recommended an additional option.[871]

Table 4
Percentage of Nobles and Grand Meadow Costs Allocated to Classes[872]

Allocation Method	Residential	C&I Non-Demand	C&I Demand	Lighting
100% Energy / Sales (DOC, OAG)	28.1%	3.1%	68.2%	0.6%
Present Revenues (Company, XLI)	35.9%	3.8%	59.4%	0.9%
Present Base Revenues (MCC)	39.2%	4.0%	55.6%	1.2%

866 Ex. 103, Peppin Rebuttal at 38.
867 Ex. 378, Nelson Surrebuttal at 12-13.
868 Ex. 262, Pollock Rebuttal at 24-26.
869 ORDER IN 2013 RATE CASE at Order Points 34 and 57.
870 Ex. 102, Peppin Direct at 18.
871 Ex. 408, Ouanes Direct at 39; Ex. 375, Nelson Direct at 31.
872 Ex. 103, Peppin Rebuttal at 22.

522. The Company, XLI and MCC maintained that the Company's economic development programs are designed to attract and retain large customers.[873] These parties therefore support allocations they claim are consistent with the purpose of the economic development programs.[874]

523. The Department and OAG recommend allocating economic development discounts using an energy-only allocator because the discounts are based on customers' energy usage.[875]

524. The Company's proposed allocation of economic development discounts is more consistent with the purpose of the economic development discount program than is the recommendation of the Department and OAG. The Company's preferred methodology should be adopted.

8. Interruptible Credits

525. The Company's CCOSS process treats interruptible credits as a cost of peaking capacity and, like other supply-side resources, allocates the costs to customer classes based on firm loads.[876]

526. As it has in past cases, the XLI asserted that the Company's treatment of interruptible credits in the CCOSS violates the matching principle.[877] According to the XLI, the CCOSS needs to be adjusted by restated class revenues at otherwise applicable firm rates and then reallocating payments to all classes relative to demand.[878]

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[873] Ex. 102, Peppin Direct at 19; Ex. 103, Peppin Rebuttal at 41. Ex. 262, Pollock Rebuttal at 22-23; Ex. 345, Maini Surrebuttal at 19.
[874] Ex. 102, Peppin Direct at 19; Ex. 103, Peppin Rebuttal at 41. Ex. 262, Pollock Rebuttal at 22-23; Ex. 345, Maini Surrebuttal at 19.
[875] Ex. 408, Ouanes Direct at 39; Ex. 375, Nelson Direct at 31.
[876] Ex. 103, Peppin Rebuttal at 13.
[877] Ex. 260, Pollock Direct at 46.
[878] Ex. 260, Pollock Direct at 46.

527. The Company explained the XLI's cost-causation arguments are not applicable when future avoided costs are higher than average embedded costs, as is the case with the Company's CCOSS.[879] The Company also noted that the Commission has agreed with the Company's treatment of interruptible loads and associated service credits in the Company's last four rate cases.[880]

528. Interruptible credits are power-supply costs and should be treated as such in the CCOSS. The Company's proposed allocation is reasonable and should be approved.

9. Treatment of Capacity Portion of Power Purchase Agreements

529. The OAG initially questioned the Company's proposed classification of the capacity portion of power purchase agreements (PPAs) in the CCOSS.[881] Ultimately, the OAG requested that the Company provide additional information related to PPAs and cost causation in its next rate case filing.[882]

530. The Company's explained that the PPA classification mirrored the classification of other capacity-related costs and that the methodology was used in the 2013 rate case.[883]

531. The Company should include additional discussion of PPAs and cost causation in its next rate case filing.

10. Settled, Resolved or Uncontested CCOSS Issues

a. Separation of Distribution Line Costs

532. The Company changed its allocation of primary distribution line costs based on analysis of data in its Geographic Information System.[884] The MCC agreed with the Company's allocations.[885]

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879 Ex. 103, Peppin Rebuttal at 14-15. *See also* Company Initial Brief at 138.
880 Ex. 103, Peppin Rebuttal at 14-15. *See also* Company Initial Brief at 138.
881 Ex. 375, Nelson Direct at 26.
882 Ex. 378, Nelson Surrebuttal at 15.
883 Ex. 103, Peppin Rebuttal at 39.
884 Ex. 102, Peppin Direct at 25-26.

533. The Company's revision is reasonable and should be adopted.

b. Direct Assignment to Lighting Class

534. Pursuant to Finding 693 from the Administrative Law Judge's report in the Company's 2013 rate case,[886] the Company engaged staff in its Capital Asset Accounting and Distribution Operations areas to identify the specific, Company-owned lighting equipment costs included in each distribution FERC Account.[887] The Company analyzed FERC Accounts 364 (Poles, Towers and Fixtures) and 373 (Street Lighting and Signal Systems).[888] Based on its analysis, the Company directly assigned $54.4 million in 2014 test year FERC Account 373 costs to the Lighting class and $35.2 million in 2014 test year FERC Account 364 costs to the Lighting class, for a total direct assignment of $89.6 million.[889] No other party provided testimony on this topic.

535. The Company's direct assignments are reasonable and should be adopted.

C. Revenue Allocation (Issue # 53)

536. Allocating revenue to customer classes is not formulaic and requires a balancing of several factors.[890] The Commission has stated all of the following are relevant to the rate design process: "economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; ability to bear, deflect, or otherwise compensate for additional costs; and in particular, the cost of service."[891]

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885 Ex. 343, Maini Direct at 26-27.
886 ALJ REPORT IN 2013 RATE CASE at ¶ 693 ("In addition, the Administrative Law Judge recommends that the Company provide a detailed analysis of its street lighting costs, both overhead and underground, as part of its next rate case filing.")
887 Ex. 102, Peppin Direct at 28.
888 Ex. 102, Peppin Direct at 28.
889 Ex. 102, Peppin Direct at 29-30.
890 *St. Paul Area Chamber of Commerce,* 312 Minn. at 260.
891 E002/GR-10-971 ORDER at 14.

537. The Company used four pricing objectives in developing its proposed class revenue allocation:

538. Produce total revenue that matches the revenue requirement for the test year in order to allow the Company a reasonable opportunity to earn its authorized return on investment;

539. Accurately reflect the resource costs of providing service and, where appropriate, the market value of service;

540. Provide sufficient flexibility in pricing levels and provisions for electric service to remain competitive in the broader energy market; and

541. Provide reasonable pricing by considering the importance of rate continuity, customer understanding, revenue stability, and administrative practicality.[892]

542. The Department used similar principles in developing its recommended revenue allocation.[893]

543. In applying their own principles, the Company and Department arrived at slightly different revenue allocations, with the Company recommending a revenue allocation that tracks the cost of service (as measured by the Company's CCOSS) more closely than does the allocation recommended by the Department.[894]

544. The MCC and XLI recommend allocating revenue to fully match cost responsibilities (as measured by their own CCOSSs).[895] The Commercial group recommends moving all classes to cost, but could also accept the Company's recommended revenue allocation if the Company's CCOSS is approved.[896]

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892 Ex. 105, Huso Direct at 6.
893 Ex. 420, Peirce Direct at 2.
894 Ex. 107, Huso Rebuttal at 6-7.
895 Ex. 345, Maini Surrebuttal at 20-21; Ex. 260, Pollock Direct at 37-38, 47.
896 Commercial Group Initial Brief at 11.

545. The OAG recommended no change in the existing revenue apportionment because, according to the OAG's CCOSS, the Residential class is at or very near cost.[897] AARP supports the OAG's recommended revenue allocation.[898]

546. The SRA supports the Company's recommended revenue allocation for the Lighting class.[899]

547. These positions result in the following recommended allocations of the proposed revenue increase in this case.

Table 5
Comparison of Recommended Allocations of Proposed Revenue Increase[900]

2014					
Class	**Company**	**Department**	**OAG**	**MCC**	**XLI**
Residential	7.6%	6.4%	6.2%	10.1%	7.8%
Non-Demand	7.7%	4.8%	6.2%	7.8%	6.6%
C&I Demand	5.4%	6.3%	6.3%	4.2%	5.3%
Lighting	0.0%	0.0%	0.0%	-13.0%	0.0%
Total	6.2%	6.2%	6.2%	6.2%	6.2%
2015					
Class	**Company**	**Department**	**OAG**	**MCC**	**XLI**
Residential	11.3%	9.9%	9.7%	*	*
Non-Demand	11.2%	8.2%	9.7%	*	*
C&I Demand	8.9%	9.8%	9.9%	*	*
Lighting	0.0%	3.1%	1.6%	*	*
Total	9.7%	9.7%	9.7%	*	*

897 Ex. 375, Nelson Direct at 38-39.
898 AARP Initial Brief at 18-19.
899 SRA Initial Brief at 12.
900 Ex. 107, Huso Rebuttal at 5, Tables 3 and 4; Ex. 422, Peirce Surrebuttal at 3-4, Tables 3 and 4; Ex. 375, Nelson Direct at 39, Tables 9 and 10; Ex. 378, Nelson Surrebuttal at 18; Ex. 343, Maini Direct at 20, Table 5; Ex. 345, Maini Surrebuttal at 20-21; Ex. 260, Pollock Direct at 46-47 (indicating XLI's proposed recommendation would move all classes to cost); Ex. 263, Pollock Surrebuttal at 31 and Schedule 22. Note, values for the OAG, MCC and XLI in the above table relate to the Company's proposed Rebuttal Testimony revenue requirement and were adjusted from Direct Testimony positions using the proportional adjustment methodology described on page 13 of Mr. Huso's Direct Testimony. The MCC and XLI did not provide specific allocations for 2015.

548. The Company identified two reasons that justify a moderated, rather than full, movement to cost. First, final rates from the 2013 rate case were implemented on December 1, 2013 and, according to the Company, a moderated movement to cost would maintain rate continuity.[901] Also, the Company proposed to refine its CCOSS as part of this case and the Company stated a moderated movement to cost would allow those changes to be reflected in rates over time.[902]

549. The Department found the Company's proposed revenue allocation would push the Residential class above cost, as measured by the Department's CCOSS.[903] The Department stated its proposed allocation moved all classes closer to cost while moderating the overall rate increases to all classes.[904]

550. The MCC and XLI asserted that cost based rates would help address the competitiveness of the Company's business rates.[905] According to the MCC, uncompetitive business rates ultimately harm all customers through decreased future sales that can produce a need for future rate increases.[906]

551. The Company has demonstrated its recommended revenue allocation is reasonable.

552. The final revenue allocation should be adjusted using the proportional adjustment methodology supported by the Company and the Department.[907]

D. Rate Design Proposals

1. Customer Charge (Issue # 54)

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[901] Ex. 105, Huso Direct at 9-10.
[902] Ex. 105, Huso Direct at 9-10.
[903] Ex. 420, Peirce Direct at 7.
[904] Ex. 420, Peirce Direct at 9.
[905] Ex. 343, Maini Direct at 30-34; Ex. 260, Pollock Direct at 39-40.
[906] Ex. 343, Maini Direct at 33.
[907] Ex. 105, Huso Direct at 12-13; Ex. 420, Peirce Direct at 11.

553. The customer charge is intended to recover the fixed cost of serving customers that is not related to energy usage. These fixed costs include metering, service lines, meter reading, and billing.[908]

554. The Company and Department both proposed to increase Residential and Small General Service customer charges.[909] The OAG, CEI, ECC and AARP opposed any increase in customer charges.[910]

Table 6
Comparison of Proposed Customer Charges

Service Category	Cost of Service[911]	Present Charge[912]	Company Proposed[913]	Department Proposed[914]
Residential Overhead	$15.70 (Average)	$8.00	$9.25	$8.50
Residential Underground – Standard		$10.00	$11.25	$10.50
Residential Heating – Overhead		$10.00	$11.25	$10.50
Residential Heating – Underground		$12.00	$13.25	$12.50
Small General Service	$16.65	$10.00	$11.50	$10.50

555. The Company and Department both asserted their proposals represent important movements to cost and improve intra-class fairness among the respective customer classes.[915]

556. The Company also stated its proposed customer charges (and associated increases) are comparable to the customer charges recently approved by the Commission in Docket No. G008/GR-13-316.[916] Finally, the Company maintained

908 Ex. 105, Huso Direct at 14.
909 Ex. 105, Huso Direct at 15; Ex. 420, Peirce Direct at 12.
910 Ex. 375, Nelson Direct at 52; Ex. 280, Chernick Direct at 28-29; Ex. 290, Cavanagh Direct at 8; Ex. 234, Colton Direct at 41; Ex. 310, Brockway Direct at 33.
911 Ex. 107, Huso Rebuttal at 29, Table 10.
912 Ex. 107, Huso Rebuttal at 25, Table 9.
913 Ex. 107, Huso Rebuttal at 25, Table 9.
914 Ex. 420, Peirce Direct at 12, Table 6.
915 Ex. 105, Huso Direct at 15; Ex. 420, Peirce Direct at 12.
916 Ex. 107, Huso Rebuttal at 27-28; Company Initial Brief at 142-143.

that its proposed customer charges leave a reasonable amount of customer-related fixed costs in energy charges as a conservation incentive.[917]

557. The Department recommended a smaller increase in the Company's customer charge, based in part, on a comparison to other Minnesota investor-owned electric utilities.[918]

558. The OAG opposed any increase in customer charges.[919] The OAG's opposition was grounded in its view that: 1) the Company's CCOSS overstates customer-related costs;[920] 2) the Company's customer charges have increased four times since 2010;[921] 3) the Company's proposed customer charges would be greater than the customer charges of other investor owned utilities;[922] and 4) the overall magnitude of the increase is too large.[923]

559. CEI claimed customer charges should not be increased because doing so would decrease conservation incentives.[924] CEI also asserted the Company was not calculating customer-related costs correctly and that intra-class equity was not an appropriate rate design consideration.[925]

560. The ECC and AARP both oppose increasing the customer charge on conservation and affordability grounds.[926]

561. The Company's proposed customer charges are reasonable and should be adopted. Increases of $1.25 and $1.50 per month are consistent with the Commission's recent decision in Docket No. G008/GR-13-316. The Company's proposed customer charges help improve intra-class equity, which is an important

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[917] Ex. 105, Huso Direct at 16-18; Ex. 107, Huso Rebuttal at 32.
[918] Ex. 420, Peirce Direct at 12-13.
[919] Ex. 375, Nelson Direct at 52.
[920] Ex. 375, Nelson Direct at 42-44; OAG Initial Brief at 77 (citing Ex. 280, Chernick Direct at 28 and Ex. 293, Chernick Rebuttal at 6-8).
[921] Ex. 375, Nelson Direct at 40-42.
[922] Ex. 378, Nelson Surrebuttal at 23.
[923] Ex. 375, Nelson Direct at 40-41, 44-52.
[924] Ex. 280, Chernick Direct at 26-27; Ex. 290, Cavanagh Direct at 8-9.
[925] Ex. 280, Chernick Direct at 27-29; Ex. 293, Chernick Rebuttal at 4-8, 14-16.
[926] Ex. 234, Colton Direct at 35, 40-41; Ex. 310, Brockway Direct at 27, 32-33.

consideration in rate design.[927] Further, both the Company and Department have shown that low-income customers exist throughout the usage spectrum,[928] which raises questions about the prudence of using the customer charge as means of addressing affordability. Finally, the OAG and CEI are incorrect about the calculation of customer-related costs,[929] negating their cost-based arguments.

2. Interruptible Rates (Issue # 52)

562. The Company proposed to increase the level C Performance Factor discounts by six percent, with corresponding increases at the other Performance Factors to maintain the current relationship between tiers and Performance Factors.[930]

Table 7
Present and Company's Proposed Interruptible Discounts
(Average Monthly Discount per kW)

Tier-PF	2-C	2-B	2-A	1-C	1-B	1-SN
Present	$4.30	$3.82	$3.10	$5.05	$4.49	$5.55
Proposed	$4.56	$4.05	$3.15	$5.35	$4.76	$5.85
Increase ($)	*$0.26*	*$0.23*	*$0.05*	*$0.30*	*$0.27*	*$0.30*
Increase (%)	*6.0%*	*6.0%*	*1.6%*	*5.9%*	*6.0%*	*5.4%*

563. The Company contended the proposed increases will improve the its ability to maintain an optimal supply of interruptible load.[931] The Company also stated that its proposed interruptible rate discounts help offset recent and proposed demand charge increases.[932]

564. The Department agreed interruptible rate discounts should be increased, but by a smaller amount than proposed by the Company.[933] The Department stated a

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927 *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 52 (June 9, 2014)(*hereinafter* G008/GR-13-316 ORDER).
928 Ex. 105, Huso Direct at 18-19; Ex. 107, Huso Rebuttal at 31-33; Ex. 420, Peirce Direct at 14-21; Ex. 422, Peirce Surrebuttal at 4-12.
929 Ex. 103, Peppin Rebuttal at 28-37; Ex. 104, Peppin Surrebuttal at 2-6, Schedule 1.
930 Ex. 105, Huso Direct at 26-28.
931 Ex. 105, Huso Direct at 27.
932 Ex. 105, Huso Direct at 27.
933 Ex. 420, Peirce Direct at 26.

smaller increase in interruptible rate discounts is appropriate given the limited number of interruptions over the last several years and the Company's statement that it has sufficient levels of interruptible load.[934]

565. The MCC and XLI both supported larger increases in interruptible rate discounts. The MCC recommended increasing interruptible rate discounts to \$77.24/kW-year for Tier 1, Performance Factor C.[935] The MCC based its proposed interruptible discounts on an avoided cost analysis.[936] XLI advocated for setting Short Notice Demand credits at \$6.76 per kW.[937] XLI also relied on avoided cost analysis.[938]

566. The Company stated that avoided cost is a useful reference point for assessing the value of interruptible service, but asserted that avoided cost cannot be used to directly set interruptible rate interruptible rate discounts.[939]

567. The Company, MCC and XLI each stated the value of interruptible service stems from the option to interrupt, not necessarily the number of interruptions.[940]

568. Interruptible load has decreased since the Company's last rate case.[941] In the face of such declines, increasing interruptible rate discounts should help the Company maintain an optimal supply of interruptible load.[942] However, the discounts proposed by the MCC and XLI are based on avoided cost, which cannot be directly applied to embedded cost rates. The levels proposed by the Company are reasonable and should be adopted.

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934 Ex. 420, Peirce Direct at 26.
935 Ex. 343, Maini Direct at 41; MCC Initial Brief at 27.
936 Ex. 343, Maini Direct at 38; Ex. 340, Schedin Direct at 23-24.
937 Ex. 260, Pollock Direct at 55.
938 Ex. 260, Pollock Direct at 53-55.
939 Ex. 107, Huso Rebuttal at 36-37.
940 Ex. 107, Huso Rebuttal at 35-36; Ex. 345, Maini Surrebuttal at 22; Ex. 263, Pollock Surrebuttal at 36.
941 Ex. 345, Maini Surrebuttal at 24; Ex. 145, Mani Opening Statement at 1 and Attachment A (Company response to MCC-157).
942 Ex. 105, Huso Direct at 27.

3. Inclining Block Rates (Issue # 80)

569. CEI and ECC initially recommended the Company implement a four-block inclining block rate (IBR) rate structure to promote conservation and affordability.[943]

570. The Company questioned whether an IBR could effectively deliver conservation and asserted an IBR could lead to adverse customer impacts.[944] The Company also raised concerns regarding the administration of an IBR.[945] Finally, the Company cautioned that an IBR should not be implemented in this case without further examination of important issues, including ways to mitigate impacts on certain customers and how the IBR would be implemented.[946]

571. The Department initially recommended further study of IBR and the implementation of a parallel billing for one year.[947]

572. The Company, CEI, ECC, and the Suburban Rate Authority entered into a Stipulation Agreement on Inclining Block Rates during the Evidentiary Hearing.[948] The parties to the Stipulation requested that the Commission open a new docket in which the Company would file a proposal for an IBR rate structure, in a form of compliance filing, 120 days after the Commission issues its final order in this proceeding.[949] The Stipulation also asks that all the evidence and arguments regarding the IBR from this case be incorporated into the new docket.[950]

573. The Department agreed that the IBR structure can be considered and implemented outside of a general rate case and noted that it no longer supported a requirement related to parallel billing.[951] The Department also agreed to convene

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[943] Ex. 280, Chernick Direct at 3; Ex. 234, Colton Direct at 4.
[944] Ex. 107, Huso Rebuttal at 10-21.
[945] Ex. 107, Huso Rebuttal at 21-23.
[946] Ex. 74, Gersack Surrebutal at 2-5; Ex. 108, Huso Surrebuttal at 2-6.
[947] Ex. 416, Grant Rebuttal at 5-6.
[948] Ex. 135, Stipulation on Inclining Block Rates.
[949] Ex. 135, Stipulation on Inclining Block Rates.
[950] Ex. 135, Stipulation on Inclining Block Rates.
[951] Ex. 446, Grant Opening Statement at 1-2.

stakeholder meetings and review the Company's IBR proposal, as stated in the Stipulation Agreement, if the Commission so orders.[952]

574. The OAG concluded the CEI IBR was not adequately developed and could not be implemented in this case.[953] The OAG also did not support the Stipulation because, in the opinion of the OAG, the evaluation process described in the Stipulation is too limited.[954]

575. IBR is not sufficiently developed to be adopted in this case. The Stipulation describes a process for additional review and development; it should be adopted. To the extent the process described in the Stipulation should be expanded or modified to address the concerns of the OAG, the Commission may do so in its final Order in this case.

E. Settled, Resolved or Uncontested Rate Design Issues

1. Low-Income Discount Program (Issue # 55)

576. The Company's Low-Income Discount Program provides eligible customers with bill payment assistance and/or discounts for their electric service; the program includes two components: the Discount Program and PowerOn.[955] The Department initially recommended expanding the Discount Program to include customers eligible for LIHEAP assistance, whether or not they are receiving such funds.[956] The Company and ECC questioned whether the expansion could be accomplished under current Minnesota law.[957] The Company also stated expansion

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952 Ex. 446, Grant Opening Statement at 1-2.
953 Ex. 377, Nelson Rebuttal at 23.
954 OAG Initial Brief at 75.
955 *See In the Matter of a Petition by Northern States Power d/b/a Xcel Energy for Approval of its Electric Lower Income Program Meter Surcharge*, Docket No. E002/M-10-854, ORDER APPROVING INCREASE IN COST RECOVERY FOR ELECTRIC LOW INCOME ENERGY PROGRAM at 2 (Jan. 28, 2011).
956 Ex. 416, Grant Rebuttal at 6.
957 Ex. 74, Gersack Surrebuttal at 11; Ex. 240, Marshall Surrebuttal at 8-9.

would also require additional administrative resources.[958] The Department eventually withdrew its proposal.[959]

2. Level of Economic Development Discounts (Issue # 56)

577. The Department recommended setting the 2014 and 2015 Competitive Response Rider (CRR) economic development discounts at 2013 levels.[960] The Company agreed to the Department's proposal for this case.[961]

578. The 2014 and 2015 Competitive Response Rider (CRR) economic development discounts should be set equal to the actual 2013 economic development discounts.

3. FCA Rider / Base Cost of Energy – Nuclear Disposal Fees (2014) (Issue # 57)

579. The Department noted that the Company collects the DOE spent nuclear disposal fees through the FCA and that the Company received notification from the DOE that the disposal fee was reduced to zero effective May 16, 2014.[962]

580. The Company responded that the spent nuclear fuel disposal fee is included in the 2014 test year as a component of the cost of fuel as well as fuel revenue (making it cost neutral), therefore the test year revenue deficiency is not materially affected by the removal of the disposal fee from the test year.[963] The Company recommended that the base cost of energy be adjusted to reflect the removal of the disposal fee in compliance at the conclusion of this case.[964]

581. The Company's proposal to reflect the removal of the disposal fee in compliance at the conclusion of this case is reasonable and should be adopted.

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[958] Ex. 74, Gersack Surrebuttal at 10-11 (discussing the additional verification process required under the Department's proposal and the funding cap and fixed discounts implemented as part of 2014 Minn. Laws Ch. 254, § 8 (amending 216B.16, subd. 14)).
[959] Department of Commerce September 30, 2014 Comments on Issues Matrix at 51.
[960] Ex. 408, Ouanes Direct at 41-44.
[961] Ex. 107, Huso Rebuttal at 38-39.
[962] Ex. 408, Ouanes Direct at 14-18.
[963] Ex. 90, Heuer Rebuttal at 14.
[964] Ex. 90, Heuer Rebuttal at 14.

4. CIP Rider: CCRC and CAF (Issue # 58)

582. The Company proposed to zero out and remove Conservation Cost Recovery Charge (CCRC) from base rates and recover all CIP program costs through the CIP Adjustment Factor (CAF).[965] The Company agreed that the CCRC be zeroed out when final rates are implemented and agreed to submit an updated Conservation Cost Recovery Adjustment (CCRA) filing 90 days before final rates are estimated to go into effect.[966]

583. The Department supported the Company's proposal.[967]

584. The Company's proposal is reasonable and should be adopted.

5. Windsource Rider (Issue # 59)

585. The Department recommended that the Company identify and justify any changes to historical data in future Windsource and FCA filings and that the Company use consistent terminology in these filings.[968] The Company accepted the Department's recommendation.[969]

586. The Department's proposal is reasonable and should be adopted.

6. Time-of-Day Energy Charges / Energy Charge Credit (Issue # 60)

587. The Department recommended the Commission approve the Company's proposed TOD Energy Charge methodology and the proposed increase in the energy charge credit.[970]

588. The Company's proposal is reasonable and should be adopted.

7. Firm Service Demand Charges (Issue # 61)

589. The Company proposed to increase firm service demand charges.[971] No other party provided testimony on this issue.

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965 Ex. 102, Peppin Direct at 33.
966 Ex. 90, Heuer Rebuttal at 10-11; Ex. 103, Peppin Rebuttal at 42.
967 Ex. 417, Davis Direct at 3-7.
968 Ex. 408, Ouanes Direct at 6-13.
969 Ex. 102, Peppin Direct at 31-32.
970 Ex. 105, Huso Direct at 21-25; Ex. 420, Peirce Direct at 22-24.

590. The Company's proposal is reasonable and should be adopted.

8. Voltage Discounts (Issue # 62)

591. The Company proposed to increase the demand charge discounts for the Transmission voltage level.[972] No other party provided testimony on this issue.

592. The Company's proposal is reasonable and should be adopted.

9. Base Energy Charges for the C&I Demand Class (Issue # 62A)

593. The Department accepted the Company's base energy charges because they appeared to be consistent with the results of the Department's modified CCOSS.[973]

594. The Company's proposal is reasonable and should be adopted.

V. TARIFF PROPOSALS

A. Coincident Peak Billing (Issue # 71)

595. The MCC proposed to amend the Company's service rules to facilitate coincident peak billing.[974]

596. The Company estimated coincident peak billing would impact at most, nine customers.[975] The Company also asserted the MCC proposal is not consistent with established rate design and that it is inappropriate for distribution capacity costs.[976] While customers may be willing to pay the additional metering costs associated with the program,[977] the Company stated that the MCC did not address cost recovery for the associated billing process changes.[978] Finally, the Company

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[971] Ex. 105, Huso Direct at 25-26.
[972] Ex. 105, Huso Direct at 28.
[973] Ex. 105, Huso Direct at 21; Ex. 420, Peirce Direct at 22.
[974] Ex. 340, Schedin Direct at 24-26; Ex. 342, Schedin Surrebuttal at 13-14.
[975] Ex. 107, Huso Rebuttal at 43.
[976] Ex. 107, Huso Rebuttal at 44.
[977] Ex. 340, Schedin Direct at 25.
[978] Ex. 107, Huso Rebuttal at 44.

maintained that if the nine customers truly are interested in being billed on a coincident peak basis, they can modify their wiring configurations accordingly.[979]

597. The MCC proposal is estimated to impact at most nine customers. At the same time, significant questions remain regarding the benefits associated with this change and the costs to implement the program. The MCC's proposal should not be adopted.

B. Definition of Contiguous (Issue # 72)

598. The MCC raised the issue of the definition of the term "contiguous" in three areas: 1) coincident peak billing; 2) solar projects and tax credits; and 3) Section No. 6, 2nd Revised Sheet No. 19.3 of the Company's Electric Rate Book.[980]

599. The Company contends no definition of "contiguous" is needed in the context of coincident peak billing because that proposal is unreasonable.[981] Next, the Company stated that Minnesota law already addresses the definition of contiguous in the context of solar projects, and that the issue is being explored in Docket No. E999/R-13-729.[982] Finally, the Company provided its interpretation of the term contiguous as it appears in its tariff.[983]

600. The MCC has not demonstrated its recommended change is needed at this time.

C. Definition of Peak Period for Time of Day Rates (Issue # 78)

601. The Company's on-peak period is currently defined as the weekday hours of 9:00 am though 9:00 pm except for seven specific holidays.[984] XLI proposed to limit the on-peak period to summer months.[985]

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979 Ex. 107, Huso Rebuttal at 43; Company Initial Brief at 145.
980 Ex. 340, Schedin Direct at 26; Ex. 342, Schedin Surrebuttal at 14-15.
981 Company Initial Brief at 145-146.
982 Minn. Stat. § 216B.164, subd. 2a (e); Ex. 136, Company response to MCC-251.
983 Ex. 136, Company response to MCC-251.
984 Es. 107, Huso Rebuttal at 44.
985 Ex. 260, Pollock Direct at 58; Ex. 263, Pollock Surrebuttal at 39-42.

602. The Company disagreed with the XLI's proposal. The Company stated its current seasonal demand charges reflect the cost difference associated with system seasonal peak capacity differentials, meaning no change is necessary.[986] The Company also claimed the seasonal peak capacity differential identified by the XLI does not impact the intra-day price differential between on- and off-peak periods.[987]

603. The XLI's proposal is unreasonable and should not be adopted.

D. Settled, Resolved or Uncontested Tariff Proposals

1. Standby Service Tariff – Manner of Service (Issue # 73)

604. MCC requested that its testimony regarding standby rates be included in Docket No. E002/M-13-315.[988] The Company agreed that the testimony could be included in the docket, though the Company did indicate it disagreed with the substance of the MCC's positions.[989]

605. The Commission may, at its option, take notice of the MCC's testimony from this case in Docket No. E002/M-13-315.

2. DG Tariff Change (Issue # 74)

606. MCC requested that the Company file changes certain changes to the DG tariff in a miscellaneous docket.[990] The Company responded that it was under the impression that the Company and MCC had agreed to work through the advisory group Rulemaking to incorporate the DG tariff change.[991] The Company agreed to file the tariff change as a miscellaneous filing.[992]

607. The Company made the DG tariff filing in Docket No. E002/M-14-648 on July 31, 2014, making this item moot.

E. Renewable Energy Purchase Tariff (Renew-a-Source) (Issue # 77)

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[986] Ex. 107, Huso Rebuttal at 45.
[987] Ex. 107, Huso Rebuttal at 45.
[988] Ex. 340, Schedin Direct at 26-30.
[989] Ex. 107, Huso Rebuttal at 40-42.
[990] Ex. 340, Schedin Direct at 22-23.
[991] Ex. 107, Huso Rebuttal at 40.
[992] Ex. 107, Huso Rebuttal at 40.

608. XLI recommended that to match around-the-clock high load customers with renewable energy resources, the Company should develop a specific tariff under which the Company can purchase and sell renewable energy directly to qualifying high load factor customers.[993] The Company would have the leverage of negotiating better prices and matching the output of defined portfolio of renewable resources with the customers' load shapes.[994] XLI recommended that the Commission order the Company to work with interested Parties and develop such a new tariff, to be filed no later than the Company's next rate case.[995] XLI also proposed guidelines for the tariff and recommended that discussions on the tariff should commence within 60 days after the final Order is issued in this case.[996]

609. The Company confirmed its commitment to begin discussions with XLI and other interested stakeholders on developing a program that addresses XLI interests, however, the Company recommended against a particular deadline for commencing discussions or making a specific tariff proposal.[997]

VI. DECOUPLING (ISSUE # 50)

A. Introduction

610. Decoupling is a "regulatory tool designed to separate a utility's revenue from changes in energy sales."[998] Its purpose "is to reduce a utility's disincentive to promote energy efficiency."[999] The Commission has previously approved three different decoupling mechanisms for natural gas utilities.[1000] The Company's proposal is the first electric utility decoupling proposal in this State.[1001]

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[993] Ex. 260, Pollack Direct at 60-61.
[994] Ex. 260, Pollack Direct at 61.
[995] Ex. 260, Pollack Direct at 62.
[996] Ex. 260, Pollack Direct at 62.
[997] Ex. 100, Clark Rebuttal at 47-48.
[998] Minn. Stat. § 216B.2412, subd. 1.
[999] Minn. Stat. § 216B.2412, subd. 1.
[1000] G008/GR-13-316 ORDER at Order Point 3. *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G007, G011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at Order Point 11 (July 13, 2012)[*hereinafter* G007,

B. The Company's Proposal

611. The Company proposed to implement a partial revenue decoupling mechanism ("RDM") for its Residential and C&I Non-Demand customers.[1002]The Company's proposed RDM is a "partial" decoupling mechanism because it excludes weather effects.[1003]

612. The Company's RDM is a per-customer model.[1004] Specifically, the revenue requirement recovered through the non-fuel energy charge, on a per-customer basis, would become the revenue baseline for calculating the decoupling deferrals under the RDM.[1005] Each month, the RDM deferral would be calculated as the difference between the monthly baseline revenue and the weather-normalized revenue collected under the volumetric rates from those customers.[1006]

613. Under the Company's proposal, monthly deferrals would be calculated as follows:

$$\text{Deferral}_{c,t} = (\text{FRC}_c \times \text{C}_{c,t}) - (\text{FEC}_c \times \text{kWh}_{c,t}^{\text{Billed,WN}})$$

where

$Deferral_{c,t}$ is the RDM deferral for customer group c in month t;

FRC_c is the fixed revenue per customer for customer group c;

$C_{c,t}$ is the number of customers in customer group c during month t;

G011/GR-10-977 ORDER]; *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at Order Point 3 (Jan. 11, 2010) (*hereinafter* G008/GR-08-1075 ORDER).

1001 Ex. 110, Hansen Rebuttal at 13; Xcel Energy Initial Brief at 146.

1002 Ex. 109, Hansen Direct at 2, 9-19. The RDM will apply to the following customer groups: residential non-space heating (customers served on rate codes A01, A02, A03, A04, A05, and A06); residential space heating (customers served on rate codes A00, A01, A02, A03, A04, A05, and A06); and small C&I customers that do not pay a demand charge (customers served on rate codes A05, A06 1S, A06 3S, A06 P, A09, A10, A11, A12, A16, A18, and A22). Ex. 109, Hansen Direct at 10.

1003 Ex. 109, Hansen Direct at 2.

1004 Ex. 109, Hansen Direct at 9.

1005 Ex. 109, Hansen Direct at 10.

1006 Ex. 109, Hansen Direct at 10.

FEC_c is the non-fuel energy rate for customer group *c*, expressed in $/kWh; and

$kWh_{c,t}^{Billed,WN}$ is the weather-normalized billed sales to customer group *c* in month *t*.[1007]

614. The Company proposed to incorporate the cumulative deferral for each customer group into customer rates every twelve months for the following year by dividing the deferral amount by the forecast of sales to the customer group.[1008] A positive cumulative deferral would result in a rate increase; a negative cumulative deferral will result in a rate decrease.[1009]

615. Under the Company's proposal, the weather-normalized billed sales to customer group c in month t ($kWh_{c,t}^{Billed,WN}$) would be calculated as billed sales to customer group c in month t, adjusted to account for deviations from normal weather conditions.[1010] Sales would be weather normalized using the same methods used to develop test year sales.[1011]

616. The fixed revenue per customer for customer group c (FRC_c) and the non-fuel energy rate for customer group c, expressed in $/kWh ($FEC_c$) would be calculated for each month of the test year, using test year revenues, numbers of customers, and sales.[1012]FRC_c would be calculated as the fixed-cost revenue requirement (described below) divided by the number of customers forecast for each month in the 2015 test year.[1013]FEC_c would be calculated as the fixed-cost revenue requirement divided by the sales forecast for each month of the 2015 test year.[1014] According to the Company, using month-specific values for these parameters, rather

[1007] Ex. 109, Hansen Direct at 10.
[1008] Ex. 109, Hansen Direct at 10-11.
[1009] Ex. 109, Hansen Direct at 11.
[1010] Ex. 109, Hansen Direct at 11.
[1011] Ex. 109, Hansen Direct at 11.
[1012] Ex. 109, Hansen Direct at 11.
[1013] Ex. 109, Hansen Direct at 11.
[1014] Ex. 109, Hansen Direct at 11.

than a single value that is constant across months, helps minimize month-to-month deferrals.[1015]

617. The total fixed revenue used in the Company's RDM would be calculated using the test year energy charges, less the CIP component, multiplied by test year sales for the corresponding customers.[1016] Separate values would be calculated for each month of the test year.[1017] The calculations would be conducted at the rate code level, with revenues aggregated up to the customer group level for purposes of the FRC_c and FEC_c calculations.[1018] Customer charge revenue would be excluded from the RDM because it is already decoupled from customer sales.[1019]

618. According to the Company, adjustments for the residential non-space heating, residential space heating, and small C&I non-demand customer groups would be calculated separately.[1020] The Company did not propose to apply a carrying charge on deferrals.[1021] At the end of a 12-month period, the total deferral for each customer group would be divided by the forecast of sales to that group for the coming year.[1022] The resulting charge would be added to or subtracted from the customer group's volumetric rate for the following 12 months.[1023] The forecast of sales for each group would be developed using the Company's normal forecasting methods.[1024]

619. The Company proposed to implement RDM rate adjustments once per year; the adjustments would remain in effect for 12 months.[1025] The Company proposed to begin calculating deferrals in the month after the Commission's final

1015 Ex. 109, Hansen Direct at 11-12.
1016 Ex. 109, Hansen Direct at 12.
1017 Ex. 109, Hansen Direct at 12.
1018 Ex. 109, Hansen Direct at 12.
1019 Ex. 109, Hansen Direct at 12.
1020 Ex. 109, Hansen Direct at 14.
1021 Ex. 109, Hansen Direct at 14.
1022 Ex. 109, Hansen Direct at 14.
1023 Ex. 109, Hansen Direct at 14.
1024 Ex. 109, Hansen Direct at 14.
1025 Ex. 109, Hansen Direct at 14-15.

Order in this proceeding.[1026] The RDM deferrals would be calculated each month through December, after which the RDM rate adjustment will be calculated and put into effect on April 1 for the following 12 months.[1027] The RDM rate adjustment would include deferrals for January through December, though, under the Company's proposal, the first year of the RDM adjustment may include less than 12 monthly deferrals due to implementation timing.[1028]

620. The Company agreed with the recommendations of the Department and OAG that the RDM should be implemented as a three-year pilot program.[1029]

621. The Company proposed to implement a five percent soft cap on its RDM.[1030] Under a soft cap, deferral amounts in excess of the cap are carried over in the deferral account for recovery in subsequent years; in contrast, under a hard cap, the deferral amount in excess of the cap is never recovered.[1031]

622. Under the Company's RDM, there is no downward limit on RDM adjustments.[1032]

623. The Company's five percent soft cap would be measured against base revenue, excluding fuel and all applicable riders.[1033] If the Commission orders the Company to implement full decoupling, then the Company requested the RDM include a 10 percent soft cap, measured against base revenue, excluding fuel and all applicable riders.[1034]

624. The Company proposed to list the RDM rate adjustment as a separate line item on customers' bills.[1035]

1026 Ex. 109, Hansen Direct at 14-15.
1027 Ex. 109, Hansen Direct at 14-15.
1028 Ex. 109, Hansen Direct at 14-15.
1029 Ex. 110, Hansen Rebuttal at 2-3; Ex. 417, Davis Direct at 40; Ex. 375, Nelson Direct at 61.
1030 Ex. 109, Hansen Direct at 15; Ex. 110, Hansen Rebuttal at 9-10.
1031 Ex. 110, Hansen Rebuttal at 10.
1032 Ex. 109, Hansen Direct at 15.
1033 Ex. 110, Hansen Rebuttal at 9.
1034 Ex. 110, Hansen Rebuttal at 9.
1035 Ex. 109, Hansen Direct at 16.

625. The Company offered to submit annual RDM reports to the Commission that would include the following items: (1) total over or under collection of allowed revenues by class; (2) total collection of prior deferred revenue; (3) calculations of the RDM deferral amounts; (4) the number of customer complaints; (5) the amount of revenues stabilized and how the stabilization impacted the Company's overall risk profile; and (6) a comparison of how revenues under traditional regulation would have differed from those collected under partial and full decoupling.[1036]

626. Finally, the Company agreed to forgo any RDM surcharges in the year following a year that it fails to achieve energy savings equal to 1.2 percent of retail sales.[1037]

627. For the reasons discussed below, the Company's RDM is reasonable and should be adopted.

C. Decoupling Policy

628. The OAG and AARP asserted no decoupling mechanism should be adopted in this case.[1038] Both the OAG and AARP based their opposition upon their view that the Company already has significant conservation incentives, making decoupling unnecessary.[1039] The OAG also stated the Company has not explained or quantified any benefits associated with the RDM and that the RDM would have adverse consequences for customers.[1040] AARP claimed the RDM unfairly shifts risks to customers, is prone to cross-subsidization, and reduces the economic benefit associated with customers' conservation efforts.[1041]

1036 Ex. 109, Hansen Direct at 18-19; Ex. 110, Hansen Rebuttal at 4; Ex. 417, Davis Direct at 22-23.
1037 Ex. 110, Hansen Rebuttal at 2-3; Ex. 417, Davis Direct at 12-14.
1038 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 4.
1039 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 9-12.
1040 OAG Initial Brief at 68-69.
1041 Ex. 310, Brockway Direct at 18, 22; Ex. 311, Brockway Rebuttal at 6

629. The Company disagreed with the premise that decoupling and conservation incentives should be treated as substitutes.[1042] According to the Company, the purpose of decoupling is to remove a utility's financial disincentive to promote conservation.[1043] The Company stated the legislature has expressly authorized incentive mechanisms "to encourage the vigorous and effective implementation of utility conservation programs."[1044] The Company interpreted the statutory structure as treating decoupling and incentive mechanisms as complements, not substitutes.[1045]

630. The Company also noted that the Commission appears to treat decoupling and conservation incentives to be compliments through the approval of decoupling for natural gas utilities with conservation incentive programs in place.[1046] The Company stated that Commissions in other states have taken a similar approach.[1047] Finally, the Company claimed its proposal fits within the State's overall policy for pursuing energy savings.[1048]

631. Regarding assertions by the OAG and AARP that decoupling increases costs without measurable benefits,[1049] the Company contended similar arguments have been raised in the past and have been rejected.[1050] The Company disagreed with the contentions of the OAG and AARP that the RDM will adversely impact customers because the Company will ultimately only collect the revenue per customer authorized in this case.[1051] The Company also claimed the level of potential RDM

1042 Company Initial Brief at 147.
1043 Company Initial Brief at 147 (citing Minn. Stat. § 216B.2412, subd. 1).
1044 Company Initial Brief at 147 (citing Minn. Stat. § 216B.16, subd. 6c).
1045 Company Initial Brief at 147. CEI appears to take a similar view. *See* Ex. 294, Cavanagh Rebuttal at 3-4.
1046 Company Initial Brief at 147.
1047 Ex. 109, Hansen Direct at 17 and Schedule 2.
1048 Company Initial Brief at 147.
1049 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 9-11, 19-20.
1050 Company Initial Brief at 148 (citing G008/GR-08-1075 ORDER at 25 ("While no pilot program can guarantee a particular result in advance, the Decoupling Statute does not require such a guarantee as a precondition for approving a pilot project.").
1051 Ex. 109, Hansen Direct at 9-11.

adjustments would be mild, that customers can offset upward RDM adjustments through less than average conservation, that percentage of bill increases are smaller for low-use customers, and that at lower usage levels, the maximum adjustment can be offset by replacing a single light bulb.[1052]

632. Finally, the Company stated it included customer protection mechanisms that will mitigate potential harm associated with the RDM. These protections include using caps as a means of limiting volatility associated with the RDM, structuring the program as a pilot, and agreeing to provide annual RDM reports.[1053]

633. CEI supported the Company's decoupling proposal.[1054] CEI asserted that it, the Company and the Department have all shown the Company's proposed decoupling mechanism would reduce the Company's disincentive to promote energy efficiency.[1055] Regarding the relationship between decoupling and conservation, CEI identified examples from both Minnesota and nationally that CEI claimed establish a link between decoupling and energy efficiency.[1056]

634. CEI acknowledged the Company's statements that compliance will be more difficult in coming years,[1057] but also recommended adopting decoupling as a means of insuring continued excellence in energy efficiency, not merely compliance.[1058]

635. CEI disagreed that decoupling leads to adverse customer impacts. First, CEI stated that decoupling would not affect the underlying, Commission-approved revenue requirement established in this case and that the Company would collect no

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1052 Ex. 109, Hansen Direct at 13 and Schedule 6; Ex. 110, Hansen Rebuttal at 6-11.
1053 Ex. 109, Hansen Direct at 15; Ex. 110, Hansen Rebuttal at 2-4, 9.
1054 CEI Initial Brief at 16.
1055 CEI Initial Brief at 17 (citing Ex. 109, Hansen Direct at 2-9; Ex. 42, Sundin Rebuttal at 3-5; Ex. 290, Cavanagh Direct at 7-8; Ex. 294, Cavanagh Rebuttal at 3-4; Ex. 417, Davis Direct at 18; and Tr. Vol. 4 at 140-141 (Davis)).
1056 Ex. 290, Cavanagh Direct at 11; CEI Initial Brief at 22-24.
1057 CEI Initial Brief at 24-25.
1058 Tr. Vol. 3 at 80 (Cavanagh).

more and no less than what is approved.[1059] Second, CEI cited a national study for the proposition that decoupling adjustments are generally very modest and do not affect benefits associated with conservation.[1060] CEI also cited the Company's analysis showing low-use customers would see smaller bill impacts (in terms of percent) and that low-use customers can conserve enough to offset the highest allowed RDM adjustment.[1061] Finally, CEI maintained the record does not establish that decoupling causes customer confusion.[1062]

636. The statutory structure of this State treats decoupling and incentive mechanisms as complements, not substitutes. The Commission apparently agrees, having approved decoupling for natural gas utilities with conservation incentive programs in place.[1063] Other states similarly treat decoupling and incentive mechanisms as different tools.[1064] Arguments that decoupling does not deliver measurable benefits have been raised and rejected in the past.[1065] Finally, the RDM would be limited to the per-customer revenues approved in this case, which, by definition, will be just and reasonable.[1066] Decoupling itself therefore does not result in adverse customer-impacts. As a matter of policy, the Company's proposal is reasonable.

1059 Tr. Vol. 3 at 83-84 (Cavanagh); CEI Initial Brief at 26.

1060 Ex. 291, Cavanagh Direct Exhibit A at 3-4.

1061 CEI Initial Brief at 26-27 (citing Ex. 111, Hansen Surrebuttal at 5-10).

1062 CEI Initial Brief at 28-29 (citing, in part, Ex. 110, Hansen Rebuttal at 16-17).

1063 G008/GR-13-316 ORDER at Order Point 3; G007, G011/GR-10-977 ORDER at Order Point 11; G008/GR-08-1075 ORDER at Order Point 3. Both CenterPoint and MERC have conservation incentive programs in place. *See e.g.*, *In the Matter of Commission Review of Utility Performance Incentives for Energy Conservation Pursuant to Minn. Stat. § 216B.241, Subd. 2c*, Docket No. E, G999/CI-08-133, ORDER ADOPTING MODIFICATIONS TO SHARED SAVINGS DEMAND SIDE MANAGEMENT FINANCIAL INCENTIVE (Dec. 20, 2012).

1064 Ex. 109, Hansen Direct at 17 and Schedule 2.

1065 *See* G008/GR-08-1075 ORDER at 25 ("While no pilot program can guarantee a particular result in advance, the Decoupling Statute does not require such a guarantee as a precondition for approving a pilot project.")

1066 Minn. Stat. § 216B.03.

D. RDM Design

637. The Department, OAG and AARP all disagree with certain design elements of the Company's proposed RDM.[1067] Each design element is discussed below.

1. Full or Partial Decoupling

638. The Department and OAG both maintained the decoupling mechanism should be a full decoupling mechanism that includes the effects of weather.[1068] The Department calculated that over the 2009-2013 and 2004-2013 periods, customers would have paid less under full decoupling than under partial decoupling.[1069] The Department and OAG both relied on this analysis to support their recommendations in favor of full decoupling.[1070]

639. The Company responded that the inclusion or exclusion of weather in the RDM has no impact on meeting the statutory purpose of decoupling, which is to reduce the disincentive to promote energy efficiency.[1071]

640. The Company also asserted that the Department's analysis was dependent on the pilot period sharing weather and economic conditions with the recent past – something that is not guaranteed.[1072] The Company provided examples showing that shifts in weather or economic assumptions would lessen or reverse the difference between partial and full decoupling identified by the Department.[1073] Further, the Company stated there is no guaranty that weather and non-weather effects will offset each other.[1074]

[1067] The OAG and AARP do not support decoupling, but if the Commission were to approve a decoupling mechanism, both indicate the design should be different from the Company's proposal. *See* OAG Initial Brief at 70-71; AARP Initial Brief at 16-18.
[1068] Ex. 417, Davis Direct at 40; Ex. 375, Nelson Direct at 60.
[1069] Ex. 417, Davis Direct at 27-29; Ex. 419, Davis Surrebuttal at 13-14.
[1070] Ex. 417, Davis Direct at 31-32; Ex. 419 Davis Surrebuttal at 14-15; Ex. 375, Nelson Direct at 55-56, 60.
[1071] Ex. 109, Hansen Direct at 12; Ex. 110, Hansen Rebuttal at 9.
[1072] Ex. 110, Hansen Rebuttal at 5.
[1073] Ex. 110, Hansen Rebuttal at 5-8.
[1074] Ex. 110, Hansen Rebuttal at 8.

641. Finally, the Company claimed that partial decoupling is consistent with its preference for a gradual approach.[1075]

642. The Company, CEI, and Department all agree that the Company's partial decoupling proposal fulfills the statutory purpose of decoupling.[1076] The Commission has approved both full and partial decoupling in the past, an indicator both may be acceptable.[1077] Partial decoupling also aligns the RDM with the Company's desire for a gradual approach, which, according to CEI, can help increase the overall efficacy of decoupling.[1078] For these reasons, it is the Company's proposal to structure its RDM as a partial decoupling mechanism should be adopted.

2. Hard or Soft Cap

643. The Department, OAG, and AARP all support a hard cap on potential RDM surcharges.[1079] All contend that a soft cap is not an actual cap because amounts above the cap are deferred for future recovery.[1080]

644. The Company supports a soft cap as a means of addressing the variability of RDM adjustments.[1081] According to the Company and CEI, a hard cap reintroduces a disincentive to promote energy efficiency and therefore undermines the purpose of decoupling.[1082] The Company also stated that most electric decoupling

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1075 Ex. 110, Hansen Rebuttal at 9.

1076 Ex. 109, Hansen Direct at 12; Ex. 417, Davis Direct at 18; Ex. 290, Cavanagh Direct at 7; Tr. Vol. 4 at 141-142 (Davis).

1077 G008/GR-13-316 ORDER at 48 ("The Commission has previously approved two decoupling pilot programs. One partial decoupling program was implemented by the Company from 2010 to 2013. The other, a full decoupling program implemented by Minnesota Energy Resources Corporation is just now underway. The Commission concludes that the modified full decoupling proposal in this proceeding is an appropriate addition to the list of pilot programs intended to aid the Commission in assessing rate decoupling's merits as a regulatory tool.")

1078 Ex. 294, Cavanagh Rebuttal at 6.

1079 Ex. 417, Davis Direct at 38; Ex. 377, Nelson Rebuttal at 39; Ex. 311, Brockway Rebuttal at 3.

1080 Ex. 417, Davis Direct at 33; Ex. 310, Brockway Direct at 21; OAG Initial Brief at 70.

1081 Ex. 111, Hansen Rebuttal at 11.

1082 Ex. 110, Hansen Rebuttal at 10; Ex. 294, Cavanagh Rebuttal at 4-5.

mechanisms have soft caps or no caps at all.[1083] Finally, the Company maintained the RDM is subject to a true cap – the revenue per customer established in this case.[1084]

645. The Department disagreed that a hard cap reintroduces a disincentive to promote energy efficiency.[1085] According to the Department's analysis, the Company "can make far more money by saving a marginal unit of energy than by making additional sales."[1086]

646. The Company's proposed soft cap is a reasonable means of managing the variability of RDM adjustments from year to year and should be adopted. A hard cap reintroduces a disincentive to promote energy efficiency, thereby undermining the purpose of decoupling. Further, the Department's reliance on the DSM financial incentive conflates two programs the legislature has deemed to be separate. And the Department itself has said that it plans to recommend changing DSM financial incentives in the future.[1087]

3. Cap Level and Cap Basis

647. The Company, Department, OAG and AARP all presented different cap levels and ways to measure the cap.

Table 8
Comparison of Recommended RDM Cap Level and Cap Basis[1088]

	Company	Department	OAG	AARP
Cap Level	5%	3%	1%	2%
Cap Basis	Base Revenue Excluding Fuel and Applicable Riders	Base Revenue Including Fuel and Applicable Riders	Base Revenue Excluding Fuel and Applicable Riders	Base Revenue Excluding Fuel and Applicable Riders

1083 Ex. 110, Hansen Rebuttal at 10 (citing Ex. 109, Hansen Direct, Schedule 2).
1084 Ex. 417, Davis Direct at 33; Ex. 109, Hansen Direct at 9-12.
1085 Ex. 419, Davis Surrebuttal at 3.
1086 Department Initial Brief at 210 (citing Ex. 419, Davis Surrebuttal at 3).
1087 Department Initial Brief at 209-210, 215.
1088 Ex. 110, Hansen Rebuttal at 9; Ex. 419, Davis Surrebuttal at 9; Ex. 375, Nelson Direct at 58; Ex. 377, Nelson Rebuttal at 38-39; Ex. 310, Brockway Direct at 21; Ex. 311, Brockway Rebuttal at 3.

648. If the Commission adopts full decoupling, then the Company requested a soft cap of 10 percent of base revenue, excluding fuel and all applicable riders.[1089]

649. The Department, OAG and AARP all asserted their proposed caps would limit customers' exposure to potentially large surcharges.[1090] Further, the Department presented an analysis showing its proposed cap would be triggered rarely.[1091]

650. The Company stated that its five percent cap was lower than the typical caps seen across the country.[1092] For example, the Company stated that caps measured according to base revenues are typically set at 10 percent.[1093] The Company also stated that most decoupling mechanisms have no caps at all.[1094]

651. The cap level and measurement proposed by the Company is consistent with national practice and should be adopted.

4. Measurement of RDM Adjustments

652. ECC supported the Company's RDM,[1095] but recommended RDM adjustments be measured on a percent of bill basis.[1096] ECC asserted the percent of bill basis is more equitable to low-income customers.[1097] AARP made a similar recommendation.[1098]

653. The Company explained RDM adjustments are applied to the variable portion of customer bills, meaning low-use customers receive smaller percentage increases than to average or higher-use customers.[1099]

1089 Ex. 110, Hansen Rebuttal at 9.
1090 Ex. 419, Davis Surrebuttal at 9; Ex. 375, Nelson Direct at 58; Ex. 377, Nelson Rebuttal at 38-39; Ex. 310, Brockway Direct at 21; Ex. 311, Brockway Rebuttal at 3.
1091 Ex. 419, Davis Surrebuttal at 8-9.
1092 Ex. 110, Hansen Rebuttal at 12.
1093 Ex. 110, Hansen Rebuttal at 12 (citing Ex. 109, Hansen Direct at Schedule 2).
1094 Ex. 110, Hansen Rebuttal at 12.
1095 ECC Initial Brief at 23.
1096 Ex. 234, Colton Direct at 35.
1097 Ex. 234, Colton Direct at 35; ECC Initial Brief at 24-25.
1098 AARP Initial Brief at 18.
1099 Ex. 111, Hansen Surrebuttal at 10; CEI Initial Brief at 27.

654. The Company's proposal to calculate RDM adjustments on a per kWh basis is reasonable and should be adopted.

5. Other RDM Design Proposals

655. In addition to design elements discussed above, the AARP recommended any decoupling mechanism include several additional design elements, including: 1) a strong and increased commitment by the Company to provide cost-effective demand-side programs and measures; 2) limit the frequency of RDM rate adjustments to more than an annual basis; 3) prevent cross-subsidization; and 4) review the basis for the weather normalization component of the RDM.[1100]

656. The Company has reaffirmed its commitment to pursuing cost-effective energy savings opportunities at numerous points in this case,[1101] eliminating the need to adopt the AARP's first recommendation. Further, the AARP's first recommendation incorrectly conflates decoupling with the State's energy savings incentive program. The Company's proposal calls for annual adjustments, meaning the AARP's second adjustment is also unnecessary. The Company has explained that its RDM is not susceptible to cross subsidization and reasonably explained why the RDM is initially limited to Residential and C&I Non-Demand customers.[1102] Finally, the Company is proposing to use the same weather normalization techniques in calculating the RDM adjustments as will be used to establish the sales forecast in this case.[1103] This means the RDM will be calculated consistent with baseline revenue per customer.

657. The AARP recommendations should not be adopted.

[1100] Ex. 310, Brockway Direct at 18; AARP Initial Brief at 17-18.

[1101] Ex. 42, Sundin Rebuttal at 3-5; Ex. 109, Hansen Direct at 6-8; Tr. Vol. 1 at 156-161 (Sundin); Tr. Vol. 3 at 94-95 (Hansen).

[1102] Ex. 109, Hansen Direct at 13-14; Ex. 110, Hansen Rebuttal at 12-13, 21-22.

[1103] Ex. 109, Hansen Direct at 11, 14.

VII. RESOLVED REVENUE REQUIREMENTS ISSUES

658. The issues in this section have been resolved, settled, or are undisputed. These matters have been reasonably resolved in the public interest and the Commission should adopt the stated resolution.

A. Sales Forecast (2014 and 2015 Step) (Issue # 13)

1. Actual Sales

659. Accurately forecasting sales is important to ensure that the Company recovers its costs, no more and no less.[1104] If the forecast overestimates sales, rates will be set too low and the Company will not be able to recover the full cost of service.[1105]

660. The Company's sales forecast was a contested issue in the prior rate case: the Department challenged the Company's forecast as being too low based on customer count, future energy prices, loss of large industrial consumers, and treatment of Demand Side Management (DSM).[1106] In the 2013 rate case, the ALJ recommended that the Commission adopt the Department's proposals and the Department's alternative of using a four-year average to calculate embedded DSM.[1107] The Commission adopted the Department's proposals but did not adopt the four-year average approach to DSM.[1108]

661. In its Direct Testimony in this case, the Company endeavored to address the concerns raised in the prior rate case,[1109] in part by utilizing a different methodology to account for future DSM.[1110] The Department disagreed with several

1104 Ex. 39, Marks Direct at 4; Ex. 405, Shah Direct at 2.
1105 Ex. 43, Hyde Direct at 2.
1106 Ex. 43, Hyde Direct at 4.
1107 Ex. 43, Hyde Direct at 4.
1108 Ex. 43, Hyde Direct at 4; Ex. 405, Shah Direct at 18.
1109 Ex. 43, Hyde Direct at 4.
1110 Ex. 39, Marks Direct at 31.

aspects of the Company's sales forecast, particularly the Company's use of DSM and its customer counts.[1111]

662. The MCC also expressed concern about the Company's sales forecasts, arguing that because the historical data on DSM achievements is derived from energy savings in the CIP plan, the Company was being compensated for energy efficiency twice – once through the CIP incentive and then again in lower sales caused by energy efficiency.[1112]

663. In rebuttal, the Company proposed that the sales forecast be based on weather-normalized actual data for the test year.[1113] This alternative methodology rendered a decision on the DSM adjustment issue and the customer count issues unnecessary.[1114] The use of this methodology is possible because it is expected that the parties will have the benefit of a full year of actual sales data for the 2014 test year before the Commission issues its decision in this proceeding in 2015.[1115] The actual sales data must be weather-normalized to be representative of sales in future years.[1116]

664. The Company committed to include weather-normalized actual sales data for the remainder of 2014 in a compliance filing.[1117] The Company agreed to use the Department's coefficients for the calculation of the weather-normalization.[1118] The Company committed to submit its weather-normalized actual electric sales data for the first eleven months of 2014 on December 16, 2014, and then to submit the December 2014 actual sales data by January 16, 2015.[1119] The Company committed to work with the Department to ensure that the calculations are correct,[1120] and also

[1111] Ex. 405, Shah Direct at 8-25.
[1112] Ex. 343, Maini Direct at 7-14.
[1113] Ex. 44, Hyde Rebuttal at 1.
[1114] Ex. 44, Hyde Rebuttal at 1; Ex. 407, Shah Surrebuttal at 9, 11.
[1115] Ex. 44, Hyde Rebuttal at 5.
[1116] Ex. 44, Hyde Rebuttal at 5.
[1117] Ex. 44, Hyde Rebuttal at 6.
[1118] Ex. 119, Hyde Opening Statement at 1.
[1119] Ex. 140, Heuer Opening Statement at 5-6.
[1120] Ex. 140, Heuer Opening Statement at 5.

agreed to work with the Department and other stakeholders in the future on the use of the price variable or other aspects of the sales forecast model.[1121]

665. The Department agreed with the Company's proposal to use weather-normalized actual data for the test year.[1122]

666. The MCC accepted the proposal by the Company and the Department to use the weather-normalized 2014 actual sales.[1123] No other party commented on the sales forecast.

667. As explained by Company witness Ms. Jannell Marks, weather-normalized actual 2013 sales were significantly lower than the forecast approved by the Commission in the last case.[1124] Weather-normalized actual 2013 sales were 0.3% higher than the Company's forecast.[1125] In this case, to avoid the significant underrecovery of a forecast set to high, or an overrecovery if the forecast were set too low, the parties have agreed to use weather-normalized actual sales. Thus, it is reasonable to adopt the sales forecast proposal agreed to by the Company, the Department, and MCC.

668. If the Commission does not adopt the recommendation to use actual sales, the Commission should apply the Company's rebuttal sales forecast for purposes of setting rates. The Company's sales forecast is supported by the evidence in the record and produces results shown to be reasonable.

2. The Company's Sales Forecast

669. The Company provided an updated forecast in the Rebuttal Testimony of Company witness Ms. Marks reflecting the use of actual data through the end of May 2014. [1126]

1121 Ex. 40, Marks Rebuttal at 17.
1122 Ex. 444, Shah Opening Statement at 1; Tr. Vol. 4 at 54 (Shah).
1123 Ex. 145, Maini Opening Statement; Tr. Vol. 4 at 13 (Maini).
1124 Ex. 38, Marks Direct at 18.
1125 Ex. 40 Marks Rebuttal at 8.
1126 Ex. 40, Marks Rebuttal.

a. DSM adjustment

670. DSM achievements have contributed to lower sales growth over the last several years.[1127] As reflected in Ms. Marks' testimony, the continued impact of embedded DSM is significantly lower than the impact of future DSM savings.[1128]

671. In response to the issues raised in the Company's last rate case, and recognizing that energy efficiency savings continue to impact the sales forecast in this case, the Company proposed a new, more transparent methodology to account for future DSM in the forecast.[1129]

672. The Company collected monthly historical data on actual DSM achievements, added the historical achievements to historical actual monthly sales to derive a time series of data excluding any DSM impacts, and used the restated time series as the input data to the regression model. The Company then reduced the forecast of sales excluding DSM by the amount of future DSM related to both historical achievements with continued impacts and planned future new programs.[1130]

673. The Department's sales forecast did not make an adjustment for DSM impacts in the test year. The Department stated that DSM savings and spending are not increasing and therefore no adjustment is necessary.[1131]

674. The Company contends that the failure to make this adjustment results in unreasonable results which are particularly pronounced when looking at the Department's forecast sales for the Large C&I class for 2014.[1132]

675. The Company also stated that the Department failed to address how DSM savings are reflected in the model and the difference between historical DSM, existing DSM and future DSM affecting sales in the test year.

1127 Ex. 38, Marks Direct at 33-34 and Figure 8.
1128 Ex. 38, Marks Direct at 8, Figure 1.
1129 Ex. 38, Marks Direct at 33.
1130 Ex. 38, Marks Direct at 33.
1131 Department Initial Brief at 174.
1132 Ex. 40, Marks Rebuttal at 20.

676. In her Direct Testimony, Ms. Marks demonstrates the difference between actual, historical DSM embedded in the forecast and forecast DSM impacting the test year.[1133]

677. Further, as Company witness Ms. Deb Sundin described, the effects of historical DSM, existing DSM and future DSM are accounted for in the model.[1134] The DSM adjustment adjusts historical sales to generate a forecast that removes the impact of all past DSM achievements, allowing the Company to project future sales independent of DSM.[1135] The continuing impacts of existing DSM (actual achievements with remaining life in the test year after subtracting the life included in historical DSM) are included, as well as new DSM achievements occurring in the forecast period.[1136] New DSM is primarily offsetting the effect of expiring measures from prior CIP program years. The Company stated that it is appropriate to include the full DSM achievements as to disqualify part or all of the adjustment would cause the sales forecast to increase artificially.[1137]

b. Verification of DSM savings

678. The Department additionally raised concerns that the DSM savings are estimates.[1138]

679. Company witness Ms. Sundin explained that these savings are subject to rigorous review.[1139] The energy savings and equipment lifetimes are calculated by the Company's engineering team applying standard industry practices and these calculations are reviewed by the Department itself.[1140]

1133 Ex. 38, Marks Direct at 32, Figure 1.
1134 Ex. 42, Sundin Rebuttal at 9.
1135 Ex. 42, Sundin Rebuttal at 10.
1136 Ex. 42, Sundin Rebuttal at 11.
1137 Ex. 42, Sundin Rebuttal at 11.
1138 Department Initial Brief at 170.
1139 Ex. 42, Sundin Rebuttal at 12.
1140 Ex. 42, Sundin Rebuttal at 12.

680. The forecast savings for these measures are built based on project and customer type for baseline and efficient equipment options, and the engineering analysis applied is built off of external industry resources and, if available, historical program results.[1141] These savings calculations are thereafter subject to a rigorous measurement and verification process.[1142] The Company then applies the savings calculations approved by the Department.[1143]

c. Impacts on forecast for small C&I

681. The Company also contends that the Department inaccurately attributes the difference between the forecast for July – December 2013 and actual results for the small commercial and industrial class to DSM.[1144]

682. As explained by Company witness, Ms. Marks, the difference between the initial forecast for the last 6 months of 2013 and actual results is not attributable to accounting for DSM savings.[1145] The Company stated that without the DSM adjustment, sales would have been overforecast for the last half of 2013 for all classes.[1146] The Company argues that the key driver of the underforecasting in the small C&I class was the underforecasting of households and total employment, not DSM.[1147]

d. Price variable

683. The Department raised concerns with the use of the price variable but recognized that to exclude the price variable would produce an unreasonable result. The Company concurred that the use of the variable improves the overall results and

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1141 Ex. 42, Sundin Rebuttal at 12.
1142 Ex. 42, Sundin Rebuttal at 13.
1143 Ex. 42, Sundin Rebuttal at 12-13.
1144 Department Initial Brief at 172.
1145 Ex. 40, Marks Rebuttal at 13.
1146 Ex. 40, Marks Rebuttal at 13-14 and Table 4.
1147 Ex. 40, Marks Rebuttal at 6-7, 13.

is appropriate for inclusion.[1148] The Company agreed to work with the Department to see if improvements may be made.[1149]

e. Customer counts

684. The Company continued to support its customer count in this case. As Company witness Ms. Marks testified, the key driver for the change was updated economic data.[1150] It is standard practice for both the household information and the employment information to be revised annually as new estimates are released.[1151] Further, while the updated data resulted in some changes, the Company noted that its 2013 forecast overall was very close to actuals in total.[1152]

685. In addition, the Company's updated forecast is based on the most up-to-date information available at the time rebuttal testimony was filed. It is appropriate to include this updated data in the sales forecast model in this case.

f. Large C&I Class

686. The Large C&I class has continued to decline for the last several years. Despite evidence of this decline, the Department's forecast for this class was 3.3 percent higher than the Company's initial forecast, 3.9 percent higher than the Company's updated forecast and 3.8 percent higher than actual sales to this class in 2013.[1153]

687. However, actual sales to the Large C&I class were 33,430 MWh lower than the Company's initial forecast and continued declines are expected.[1154] The Department's forecast would result in a base revenue adjustment of $11.6 million when the evidence supports that sales to these customers has declined.[1155]

1148 Ex. 40, Marks Rebuttal at 17.
1149 Ex. 40, Marks Rebuttal at 17.
1150 Ex. 40, Marks Rebuttal at 6-7.
1151 Ex. 40, Marks Rebuttal at 8.
1152 Ex. 40, Marks Rebuttal at 7.
1153 Ex. 40, Marks Rebuttal at 5 and 20.
1154 Ex. 40, Marks Rebuttal at 5.
1155 Ex. 40, Marks Rebuttal at 20.

3. Conclusion

688. While the record supports the use of the Company's sales forecast in this case, the Company, the Department, and the MCC agree that the use of weather-normalized 2014 sales is the preferred solution in the case. If the Commission declines to adopt this proposal, the Commission should adopt the Company's forecast as supported by the evidence in the record and accurately forecasting test year sales taking into account updated economic data, the impact of energy efficiency efforts, and the continued decline in sales for the Company's large C&I customers.

B. Property Tax Amount (2014) (Issue # 14)

689. Minnesota property taxes represent a significant expense to the Company. In Direct Testimony, the Company provided a detailed explanation of the methodology by which the Company forecasts its 2014 property taxes.[1156] The Company noted that its Minnesota property taxes, which represent almost 97 percent of its total property tax expense,[1157] have increased rapidly over the last ten years.[1158] The Company forecasted its 2014 electric and natural gas property taxes (including Minnesota, North Dakota, and South Dakota) to be $206 million on an NSPM total Company basis,[1159] resulting in property taxes attributable to Minnesota electric operations for purposes of ratemaking to be $149.2 million.[1160]

690. The Department, arguing that the Company had over-recovered its allowed and/or forecasted property taxes in past years by an average of 9 percent, recommended that the 2014 property tax expense be reduced by 9 percent, or 13.5 million, to $135.7 million.[1161]

[1156] Ex. 33, Duevel Direct at 1-18.
[1157] Ex. 33, Duevel Direct at 2.
[1158] Ex. 33, Duevel Direct at 18-23.
[1159] Ex. 33, Duevel Direct at 1.
[1160] Ex. 33, Duevel Direct at 1-2, Schedule 10; *see also* Ex. 14 at Tab A-58.
[1161] Ex. 439, Lusti Direct at 36.

691. In Rebuttal Testimony, the Company used additional information it had received from the Department of Revenue (DOR) to validate its original forecast.[1162] Using the additional information, the Company showed the total 2014 electric and natural gas property taxes would be $200.1 million.[1163] This resulted in property tax expenses attributable to Minnesota electric operations, for purposes of ratemaking, of $145 million.[1164]

692. In Surrebuttal Testimony, the Department acknowledged that its prior analysis had been flawed.[1165] The Department noted, though, that during the five-year period from 2009 through 2013, the Company's Minnesota property tax expenses had increased an average of 10.72 percent, and thus argued that the Company's 2014 property tax expense for ratemaking should be $136 million, a 10.72% increase over the actual 2013 figure.[1166]

693. In the alternative, the Department proposed a reduction of $9.0 million from the Company's original $150 million figure, based on the percent difference between the Company's initial 2014 test year forecast presented in the Company's Direct Testimony and the validated 2014 property tax presented in the Company's Rebuttal Testimony, as well as a further adjustment based on the difference between the Company's June 2013 forecast of 2013 property taxes and actual 2013 property taxes.[1167] The result of the Department's alternative proposal was a property tax expense for ratemaking purposes of $141 million, a $9 million reduction from the Company's initial proposal.[1168]

1162 Ex. 34, Duevel Rebuttal at 3.
1163 Ex. 34, Duevel Rebuttal at 3.
1164 Tr. Vol. 4 at 138 (Duevel).
1165 Ex. 442, Lusti Surrebuttal at 25-26.
1166 Ex. 442, Lusti Surrebuttal at 29.
1167 Ex. 442, Lusti Surrebuttal at 30.
1168 Ex. 442, Lusti Surrebuttal at 30.

694. The MCC did not object to the validated figures presented in the Company's Rebuttal Testimony, but also did not object to the Department's alternative proposal of $141 million.[1169]

695. The Company agreed to the Department's alternative proposal to reduce the 2014 property tax expense to $141 million, subject to a true-up for the actual 2014 property taxes.[1170] Under the true-up, the total 2014 test year property tax expense would be capped at the Company's $145 million figure; there is no downward limit on the true-up.[1171] The Department and the MCC agreed to the Company's true-up proposal.[1172] No other party commented on 2014 property taxes.

696. The Company and the Department agreed on a procedure for the property tax true-up. The Company will file its actual year-end 2014 property tax expense with the Commission on January 16, 2015, based on Truth-in-Taxation Notices received in November and December of 2014.[1173] The Company and the Department recommended that the Commission reflect the 2014 year-end property tax expense in its determination of the Company's 2014 revenue requirement and the 2014 year-end property tax expense would be reflected in final rates in this case, up to a cap of $145.0 million (Minnesota electric jurisdiction).[1174]

697. The Company will also make a compliance filing on June 30, 2015 detailing the final 2014 property tax expense reflected on property tax statements received in the spring of 2015.[1175] If the actual 2014 property taxes reflected on those statements is less than the year-end 2014 property tax expense (*i.e.*, the 2014 test year

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[1169] Ex. 342, Schedin Surrebuttal at 12.
[1170] Ex. 117, Duevel Opening Statement at 1; Ex. 140, Heuer Opening Statement at 2.
[1171] Ex. 117, Duevel Opening Statement at 1; Tr. Vol. 1 at 137-39 (Duevel); Ex. 451, Lusti Opening Statement at 2 ("no downward bound").
[1172] Ex. 451, Lusti Opening Statement at 2; Tr. Vol. 1 at 137 (Duevel).
[1173] Ex. 451, Lusti Opening Statement at 2.
[1174] Ex. 451, Lusti Opening Statement at 2; Tr. Vol. 3 at 161-164, 168-69 (Heuer).
[1175] Ex. 451, Lusti Opening Statement at 2.

property tax expense), the Company agreed to make ongoing annual refunds of the difference until the Company files the next rate case.[1176]

698. The resolution reached by the Company and the Department is reasonable and should be adopted.

699. If the Commission does not accept the resolution reached by the Company and the Department, then 2014 test year property taxes should be set at $145 million for the Minnesota electric jurisdiction, as calculated in Mr. Duevel's Rebuttal Testimony.[1177] The expense calculation included in Mr. Duevel's Rebuttal Testimony reflected actual information that will be used to determine the Company's actual 2014 property taxes. This leads to a more accurate and reasonable result than any of the forecasts presented by the Department.

700. If no actual information related to the Company's 2014 property taxes is to be reflected in the determination of the 2014 test year expense, then the Company's Direct Testimony forecast of $150 million on a Minnesota electric jurisdiction basis is the most reasonable option and should be adopted.

C. Emissions Control Chemical Costs (2014) (Issue # 15)

701. One of the components in the Company's Energy Supply Operations and Maintenance budget is the cost of chemicals (sometimes referred to as "base commodities") used to reduce emissions.[1178] The Company provided a detailed explanation of the factors affecting the costs for these chemicals, such as plant operations and efficiencies, commodity costs, the Company's purchasing process, and the addition of emissions control equipment.[1179] The Company requested recovery of approximately $10.305 million for emissions control chemical costs for the 2014 test year.[1180] The Company noted that its request was based on a new methodology that

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[1176] Ex. 451, Lusti Opening Statement at 2.
[1177] Ex. 34, Duevel Rebuttal at 3.
[1178] Ex. 59, Mills Direct at 2, 8-9, 16-18.
[1179] Ex. 59, Mills Direct at 18-29.
[1180] Ex. 59, Mills Direct at Sch. 4.

was developed in response to comments in the prior rate case,[1181] and explained that various differences between the current request and costs incurred during previous years were the result of Sherco 3 coming back on-line and other various factors.[1182]

702. The Department observed that the Company had generally over-recovered for emissions chemical costs each year since 2009.[1183] The Department recommended using a three-year historical average of the Company's actual emissions control chemical costs, adjusted for the Sherco 3 outage and for anticipated chemical use at Sherco 1 and 2.[1184] Based on this approach, the Department recommended a downward adjustment of $2.265 million ($1.876 million for other than Sherco chemical costs, and $0.389 million for Sherco chemical costs) to the Company's request, i.e., that the 2014 test year emissions control chemical costs for ratemaking purposes should be $8.040 million.[1185]

703. At the evidentiary hearing, the Company accepted the Department's recommended downward adjustment.[1186] No other parties presented evidence on this issue.

D. Insurance – Surplus Distributions from Industry Mutual Insurance Pools (2014) (Issue # 16)

704. The Company's insurance for certain difficult-to-place risks is provided through industry mutual insurance pools such as Energy Insurance Mutual (EIM) and Nuclear Electric Insurance Limited (NEIL).[1187] From time to time, these insurance pools return excess premiums to the Company, in the form of surplus distributions or continuity credits.[1188]

1181 Ex. 59, Mills Direct at 20-21.
1182 Ex. 59, Mills Direct at 24-26; Ex. 60, Mills Rebuttal at 3-10.
1183 Ex. 431, Campbell Direct at 15-25; Campbell Surrebuttal at 23-24.
1184 Ex. 431, Campbell Direct at 25-26; Campbell Surrebuttal at 24-26.
1185 Ex. 431, Campbell Direct at 26; Ex. 439, Lusti Direct at 40; Ex. 442, Lusti Surrebuttal at 32.
1186 Ex. 140, Heuer Opening Statement at 1; Ex. 125, Mills Opening Statement at 1; Ex. 450, Campbell Opening Statement at 2.
1187 Ex. 36, Anderson Direct at 14-15, 17, 42.
1188 Ex. 425, Byrne Direct at 24.

705. The Department noted that the Company had included certain continuity credits in its 2014 test year budget (which reduced test year insurance costs), but had not included anticipated surplus distributions from NEIL and EIM in the 2014 test year budget.[1189]

706. The Company explained that unlike the continuity credits, which occur regularly, the anticipated NEIL and EIM surplus distributions had not been included in the 2014 test year budget because they were irregular: each was only the second such distribution since the economic downturn in 2008.[1190]

707. The Department recommended that the anticipated NEIL and EIM surplus distributions, a total of $1,662,299, should be included in the 2014 test year budget so that Minnesota ratepayers could receive the benefit of the distributions.[1191]

708. In Rebuttal Testimony, the Company agreed to include the anticipated surplus distributions from NEIL and EIM in the 2014 test year budget, because even though the distributions occur irregularly, they were received prior to the closing of the record in the rate case.[1192]

709. As a result, the Department considered this issue resolved.[1193] No other party commented on the issue of surplus distributions from industry mutual insurance pools.

E. Treatment of Capitalized Pension and Related Benefit Costs –Rate Based Factor Method (Issue #17)

710. The Company proposed to use the "rate base factor" method developed in the Company's last rate case (Docket No. E002/GR-12-961) to determine pension and related benefit O&M expenses. This method applies a rate base factor to the

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[1189] Ex. 425, Byrne Direct at 24.
[1190] Ex. 425, Byrne Direct at 24-25.
[1191] Ex. 425, Byrne Direct at 25-27; Ex. 439, Lusti Direct at 39.
[1192] Ex. 37, Anderson Rebuttal at 3; Ex. 90, Heuer Rebuttal at 12-13.
[1193] Ex. 428, Byrne Surrebuttal at 11.

beginning-of-year/end-of-year average of the capitalized portion of costs and thus converts the capital adjustments to revenue requirements.[1194]

711. The Department accepted the Company's proposal.[1195]

F. Qualified Pension- Measurement Date (Issue #18)

712. The Company proposed that the same measurement date be used to calculate all pension and benefit expenses, including qualified pension.[1196] The Company recommended using December 31, 2013 as the measurement date because it provides the most current information available and results in an adjustment that favors customers.[1197]

713. The Department did not initially accept the Company's proposal to update the measurement date for the qualified pension because the update increased the pension expense and because the Department had concerns about the financial performance of the pension assets.[1198]

714. In Surrebuttal Testimony, the Department accepted the Company's proposal to update the measurement date for the qualified pension to December 31, 2013.[1199]

715. This results in an increase of $1,011,492 (both O&M and capital) in the test year revenue requirements.[1200]

G. Non-Qualified Pension-Restoration Plan (2014) (Issue #20)

716. The Company's non-qualified pension restoration plan provides supplemental benefits to those employees whose wages exceed the IRS-determined

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1194 Ex. 90, Heuer Rebuttal at 18-20.
1195 Ex. 435, Campbell Surrebuttal at 74-75.
1196 Ex. 83, Schrubbe Rebuttal at 11.
1197 Ex. 83, Schrubbe Rebuttal at 11.
1198 Ex. 435, Campbell Surrebuttal at 87.
1199 Ex. 435, Campbell Surrebuttal at 88.
1200 Ex. 90, Heuer Rebuttal at 20; Ex. 450, Campbell Opening Statement at 5.

compensation limits to give them equal level of benefits than those employees who can participate in qualified pension plans.[1201]

717. The Department recommended disallowance of all non-qualified pension restoration plan costs because it is not reasonable for ratepayers to finance these benefits.[1202] In Rebuttal Testimony, the Company accepted the Department's recommendation to exclude non-qualified pension restoration plan costs in this case.[1203]

718. This results in a reduction of $704,000 in test year revenue requirements (both O&M and capital).[1204]

H. Post-Employment Benefits- Long-term Disability and Workers' Compensation (Issue #21)

719. The Company requested recovery of $3.79 million in O&M expenses and $190,152 in capital costs related to post-employment benefits (primarily long-term disability and workers' compensation) for former or inactive employees after employment but before retirement.[1205] The Company used a measurement date of December 31, 2012 and a discount rate of 3.74 to calculated the test year expenses.[1206]

720. The Department agreed that the Company's 3.74 discount rate was reasonable.[1207] The Department recommended using the most recent information available and updating the measurement date to December 31, 2013.[1208] The Department provided an adjustment that reduced post-employment FAS 112 O&M expenses by $412,498 of the test year.[1209]

1201 Ex. 81, Moeller Direct at 11; Ex. 78, Figoli Direct at 73-76.
1202 Ex. 429, Campbell Direct at 141-144.
1203 Ex. 80, Figoli Rebuttal at 17.
1204 Ex. 90, Heuer Rebuttal at 21.
1205 Ex. 81, Moeller Direct at 119.
1206 Ex. 423, Byrne Direct at 45.
1207 Ex. 423, Byrne Direct at 46.
1208 Ex. 423, Byrne Direct at 43-47.
1209 Ex. 423, Byrne Direct at 46-47.

721. The Department proposed a corresponding proportional (52 percent) reduction to FAS 112 capital costs of $99,172 reduction.[1210]

722. The Company agreed with the Department's recommendations and proposed to combine the O&M and capital adjustments into one revenue requirement reduction of $421,463 (both O&M and capital).[1211] The Department accepted the Company's calculated adjustment.[1212]

I. Active Health Care and Welfare Costs (2014) (Issue #22)

723. The Company requested recovery of $33,264,053 in active health care costs and a total of $36,443,475 in combined active health and welfare costs for the test year.[1213] The Company calculated the test year amount by utilizing actual active health care costs from 2011 (weighted at 20 percent) and 2012 (weighted at 80 percent), making adjustments for changes in plan design, regulation, administrative fees, etc., and then trending the data forward to 2014 using a 7.0 percent inflation factor.[1214]

724. The Department recommended that the 2014 active health case O&M costs be based on a three-year historical average of $33,136,458, resulting in a downward adjustment of $3,307,017.[1215]

725. The Department recommended use of an inflation factor of 2.85 percent over 2013 claims expenses as this is an average of the annual percentage increases in claims expenses in 2012 and 2013.[1216] This results in a reduction to the Company's requested test year active health care O&M expense of $1,056,493.[1217] The

[1210] Ex. 423, Byrne Direct at 23; Ex. 427, Byrne Surrebuttal at 13.
[1211] Ex. 90, Heuer Rebuttal at 23; Ex. 83, Schrubbe Rebuttal at 60;
[1212] Ex. 427, Byrne Surrebuttal at 13.
[1213] Ex. 80, Moeller Direct at 129.
[1214] Ex. 80, Moeller Direct at 130-131.
[1215] Ex. 427, Byrne Surrebuttal at 13-14.
[1216] Ex. 427, Byrne Surrebuttal at 20-21.
[1217] Ex. 427, Byrne Surrebuttal at 20-21.

Department recommended a proportional adjustment to the active health care capital costs of $225,480.[1218]

726. The Company agreed to the Department's recommended reduction in active health care costs of $1.082 million (O&M and capital) to the test year revenue requirements.[1219]

J. Nuclear Cash-Based Retention Program (2014) (Issue #23)

727. The Company proposed recovery of $516,466[1220] in costs for one component of its Nuclear Retention Program, the Nuclear Cash-Based Retention agreements.[1221] The Company's Nuclear Retention Program is a compensation tool to help attract and retain employees that are qualified to work in nuclear plants.[1222]

728. The Department stated it is reasonable to conclude that the Nuclear Retention Program was created in 2012 to provide some of the Company's nuclear employees additional compensation and to replace the amounts they would otherwise have received through the AIP.[1223] The Department recommended removing all the costs associated with the Nuclear Retention Program from the test year.[1224]

729. During the evidentiary hearing, the Company accepted the Department's proposal to remove all the costs associated with the Nuclear Retention Program from the test year.[1225]

730. This results in a $516,466 reduction in test year revenue requirements.[1226]

1218 Ex. 427, Byrne Surrebuttal at 20-21.
1219 Ex. 140, Heuer Opening Statement at 2.
1220 The Company's proposed recovery is based on a Total Company number of $694,736 of nuclear retention program expenses. The Minnesota jurisdictional amount is $516,466 after applying a 74.34 percent allocation factor. Ex. 437, Lusti Direct at 31.
1221 Ex. 78, Figoli Direct at 51-52.
1222 Ex. 78, Figoli Direct at 51.
1223 Ex. 437, Lusti Direct at 35.
1224 Ex. 437, Lusti Direct at 35.
1225 Ex. 140, Heuer Opening Statement at 2.
1226 Ex. 140, Heuer Opening Statement at 2.

K. Customer Care O&M Expenses - Miscellaneous O&M Credits (Issue # 24)

731. The Company requested Customer Care O&M Expenses that included forecasted Miscellaneous O&M Credits.[1227] The Miscellaneous O&M Credits offset O&M expenses related to Meter Reading and Field Collections.[1228]

732. In Direct Testimony, the Department noted the Company has over-recovered Customer Care O&M expenses by $3.2 million from 2011 to 2013 and that much of the over-recovery is attributed to higher than forecasted Miscellaneous O&M Credits.[1229] The Department recommended that the Company's 2014 test year Miscellaneous O&M Credits to be set at the amount of the average Miscellaneous O&M Credits from 2010 through 2013, at $1.216 million.[1230]

733. In Rebuttal Testimony, the Company agreed with the Department's proposed adjustment to the forecasted Miscellaneous O&M Credits, but disagreed with the Department's use historical averages.[1231] The Company noted that the Department's recommendation closely correlates with the Company's current budget forecast for 2014 Miscellaneous O&M Credits, which was $1.218 million.[1232] The Company also noted that the Department's proposal to set the 2014 Miscellaneous O&M Credits at $1.216 million results in a decrease in test year revenue requirement of $503,142.[1233]

734. In Surrebuttal Testimony, the Department noted the Company and Department continue to disagree on the rationale of the Miscellaneous O&M Credit

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1227 Ex. 71, Gersack Direct at 16 and Schedule 2.
1228 Ex. 71, Gersack Direct at 16.
1229 Ex. 425, Byrne Direct at 11-13.
1230 Ex. 423, Byrne Direct at 49; Ex. 437, Lusti Direct at 38.
1231 Ex. 73, Gersack Rebuttal at 2-3.
1232 Ex. 73, Gersack Rebuttal at 5-6.
1233 Ex. 90, Heuer Rebuttal at 12.

adjustment, but agree on the amount to be included, which effectively resolved the issue.[1234]

L. Nuclear Fees (Issue # 25)

735. The Company requested recovered recovery of the Minnesota jurisdictional portion of $35.2 million for nuclear fees in the test year.[1235] The Department recommended the Company recover $23.75 million, which results in a $0.25 million or 1.1 percent increase from the Department's calculated actual nuclear fees costs from 2013, resulting in a decrease in test year power production expense by $1.9 million.[1236]

736. In Rebuttal Testimony, the Company disagreed with the Departments recommendation to allow only a 1.1 percent increase in nuclear fees from 2013, because the Department relied on the abnormally low 2013 Nuclear Regulatory Commission (NRC) actual fees for the starting point and because all nuclear fees other than the NRC fees increased by at least 10 percent from 2011 to 2013.[1237] The Company also noted that a recent update to NRC pre-reactor portions of NRC's 2014 Annual Fee is 19 percent higher than in 2013, which justifies the Company's test year 2014 nuclear fee amount.[1238]

737. In Surrebuttal Testimony, the Department noted the justification for NRC Fees and recommended the amount of $15.00 million for the Minnesota jurisdiction.[1239] The Department continued to disagree with the Company's 2014 test year amounts for other nuclear fees and recommended a $1.00 million downward adjustment to revenue requirements.[1240]

[1234] Ex. 427, Byrne Surrebuttal at 7.
[1235] Ex. 52, O'Connor Direct at 112.
[1236] Ex. 429, Campbell Direct at 74-75; Ex. 437, Lusti Direct at 42 and Sch. 7.
[1237] Ex. 54, O'Connor Rebuttal at 31-35.
[1238] Ex. 54, O'Connor Rebuttal at 35-37.
[1239] Ex. 435, Campbell Surrebuttal at 61-62.
[1240] Ex. 435, Campbell Surrebuttal at 62-65; Ex. 442, Lusti Surrebuttal at 32.

738. During the evidentiary hearing, the Company accepted the Department's final recommended $1.00 million reduction to revenue requirement.[1241] The Department recognized the issue as resolved.[1242]

M. Investor Relations Costs (Issue # 26)

739. The Company requested recovery of 50 percent of investor relations costs with the exception of requesting recovery of all stock registration fees for the Minnesota electric jurisdiction, resulting in a decrease in test year revenue requirement of $385,000.[1243] In Direct Testimony, the Company presented information supporting its request,[1244] and noted that the Company believed this adjustment was consistent with the prior rate cases.[1245]

740. In Direct Testimony, the Department disagreed with the Company's exception for stock registration fees, and recommended that the 50 percent of all investor relations costs, including the stock registration fees, be removed from the test year.[1246] The Department's proposal would decrease the test year revenue requirement by an additional $78,140.[1247]

741. In Rebuttal Testimony, the Company accepted the Department's proposal.[1248]

742. In Surrebuttal Testimony, the Department confirmed the agreed upon adjustment.[1249]

[1241] Ex. 140, Heuer Opening Statement at 2; Tr. Vol. 1 at 218 (Heuer); Tr. Vol. 3 at 140 (Heuer).
[1242] Ex. 450, Campbell Opening Statement at 2.
[1243] Ex. 88, Heuer Direct at 138-139; Ex. 30, Tyson Direct at 44.
[1244] Ex. 30, Tyson Direct at 38-44.
[1245] Ex. 86, Stitt Direct at 60-61; Ex. 88, Heuer Direct at 138-139.
[1246] Ex. 423, Byrne Direct at 7-10.
[1247] Ex. 423, Byrne Direct at 10, 48-49; Ex. 437, Lusti Direct at 38.
[1248] Ex. 90, Heuer Rebuttal at 13; Ex. 31, Tyson Rebuttal at 30.
[1249] Ex. 427, Byrne Surrebuttal at 4-5; Ex. 442, Lusti Surrebuttal at 31.

N. Business Systems General Ledger System (Issue # 28)

743. In Direct Testimony, the Company included $27.721 million in capital costs in the 2015 Step related to the Business Systems' General Ledger System project, scheduled to go in-service during the fourth quarter of 2015.[1250]

744. In Direct Testimony, the Department proposed an adjustment to remove all General Ledger System project costs from the 2015 Step, because the Department did not find that the Company had shown that the system will be used and useful for Minnesota ratepayers until January 1, 2016.[1251] The Department's proposal would reduce the test-year rate base by $8.8 million and remove the Minnesota Jurisdictional portion of $27.721 million in capital costs from the 2015 Step.[1252]

745. The Company disagreed with the Department's proposal.[1253] In Rebuttal Testimony, the Company noted that running the new general ledger system parallel to the old system does not mean the system is not used and useful.[1254] The Company further clarified that the new general ledger testing period would begin in April 2015, and be fully operational on November 1, 2015, so as to align with the Company's financial year-end date.[1255]

746. In Surrebuttal Testimony, the Department agreed that the General Ledger System project would be in-service on December 31, 2015 and no longer recommended the adjustment.[1256]

1250 Ex. 62, Harkness Direct at 48-52 and Sch. 2; Ex. 18, May 7, 2014 Errata to the Application, Direct Testimony and Schedules, Errata Summary at 6.
1251 Ex. 423, Byrne Direct at 21-22.
1252 Ex. 427, Lusti Direct at 47, Ex. 423; Byrne Direct at 21-22.
1253 Ex. 64, Robinson Rebuttal at 8; Ex. 94, Perkett Rebuttal at 51; Ex. 64, Harkness Rebuttal at 3.
1254 Ex. 94, Perkett at 50-51; *See* Ex. 64, Harkness Rebuttal at 1-12.
1255 Ex. 64, Harkness Rebuttal at 5, 7-8.
1256 Ex. 427, Byrne Surrebuttal at 9-10; Ex. 442, Lusti Surrebuttal at 38.

O. Prairie Island Administration Building (Issue # 29)

747. In Direct Testimony, the Company included $22.6 million for project costs associated with the Prairie Island Administration Building.[1257] In Direct Testimony, Department challenged the reasonableness of the Company's scheduled in-service date of December 31, 2014 and recommended an in-service date of March 1, 2015.[1258] The Departments proposal would have the effect of decreasing the test year rate base by $1.8 million, and decreasing the 2015 Step by $1.1 million.[1259]

748. The Company provided further explanation for the costs in Rebuttal Testimony and provided additional explanation regarding the December 2014 in-service date.[1260] The Company did not agree with the Department's proposed modification of the in-service date.[1261]

749. In Surrebuttal Testimony, the Department agreed with the Company, and no longer recommended the change to the in-service date or the corresponding downward capital adjustment.[1262]

P. Pleasant Valley Wind and Borders Wind (2015 Step) (Issue #30)

750. The Company proposed to include the capital costs for two wind projects, Pleasant Valley Wind and Borders Wind, in the 2015 Step.[1263]

751. The Company accepted the Department's recommendation to include estimated Production Tax Credits (PTC) ($11.093 million) in base rates along with project costs, subject to a true-up of the PTCs in the Renewable Energy Standard ("RES") Rider.[1264] However, the Company was also open to MCC's recommendation

[1257] Ex. 52, O'Connor Direct at 69-70.
[1258] Ex. $31, Campbell Direct at 154-156.
[1259] Ex. 437, Lusti Direct at 22, 49.
[1260] Ex. 54, O'Connor Rebuttal at 42-44; Ex. 94, Perkett Rebuttal at 48-50.
[1261] Ex. 54, O'Connor Rebuttal at 42-44; Ex. 94, Perkett Rebuttal at 48-50.
[1262] Ex. 436, Campbell Surrebuttal at 17-20; Ex. 442, Lusti Surrebuttal at 10, 41.
[1263] Ex. 58, Mills Direct at 61-66.
[1264] Ex. 429, Campbell Direct at 40-41; Ex. 100, Clark Rebuttal at 28.

to include both the capital costs and associated PTCs for Pleasant Valley and Border Winds in the RES Rider.[1265]

752. The Department originally stated that the Company has not shown why it is reasonable to recover capital costs for the Pleasant Valley and Border Winds projects in excess of the amounts that were approved in the Wind Acquisition Dockets and believed that the project costs were overstated in the 2015 Step.[1266] In Surrebuttal, the Department accepted the Company's explanation of discrepancies between the capital costs included in Mr. Mills' and Mr. Robinson's Direct Testimonies was due to AFUDC and no longer proposed a downward adjustment of $5,672,482 for capital project costs.[1267]

753. The OAG supported the recommendations made by the Department in its Direct Testimony, including the downward adjustment of $5,672,482 and inclusion of the PTC for these wind projects in base rates.[1268]

754. Based on their late 2015 in-service dates, MCC initially recommended removing all the capital costs related to these two wind projects from the 2015 Step, or alternatively, MCC recommended using a 13-month average rate base methodology.[1269] The Company stated that MCC's proposal does not reflect how rate base is calculated using beginning of year/end of year averages.[1270] In addition, the methodology used should be consistent for all capital additions calculations.[1271] In Surrebuttal Testimony, MCC recommended that the Company should recover the costs for the two wind projects through the RES Rider.[1272]

1265 Ex. 100, Clark Rebuttal at 28.
1266 Ex. 429, Campbell Direct at 38-39.
1267 Ex. 435, Campbell Surrebuttal at 4-5.
1268 Ex. 372, Lindell Rebuttal at 3-5.
1269 Ex. 343, Maini Direct at 3-4.
1270 Ex. 94, Perkett Rebuttal at 52-53.
1271 Ex. 94, Perkett Rebuttal at 52-53.
1272 Ex. 345, Maini Rebuttal at 3-4.

755. Inclusion of the costs for two wind projects in the 2015 Step is reasonable as is recovery of these costs in the RES Rider. The OAG's recommended adjustment is not supported by the record.

Q. Ratepayer Protection Mechanism for Company-Owned Wind Farm (Issue #31)

756. MCC recommended that a "ratepayer protection mechanism" be imposed for Company-owned wind projects.[1273]

757. Given the limited time in the present proceeding, the Company stated that this case is not the best forum to develop a ratepayer protection mechanism for Company-owned wind farm costs, and proposed to work with MCC and other Parties prior to January 1, 2015 and report results in the RES Rider Docket.[1274]

758. The MCC agreed to the Company's proposal.[1275]

R. Property Tax Amount (2015 Step) (Issue # 32)

759. In Direct Testimony, the Company provided a detailed explanation of its forecast that its total 2015 property taxes would be $221.4 million, resulting in property tax expense for 2015 for the Minnesota electric jurisdiction of $156.5 million.[1276] The Company also explained how the forecasted 2015 property tax expense was properly included in the calculations for the 2015 Step revenue requirement analysis.[1277]

760. The Department recommended reducing the 2015 Step property tax expense by nine percent to reflect a nine percent cumulative over-recovery for the period from 2001 through 2013.[1278]

761. In Rebuttal Testimony, the Company defended its property tax calculation and instead proposed to include in the 2015 Step only those property tax

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[1273] Ex. 343, Maini Direct at 2-6.
[1274] Ex. 100, Clark Rebuttal at 29.
[1275] Ex. 345, Maini Surrebuttal at 4
[1276] Ex. 33, Duevel Direct at 3-4, 15-18; Ex. 89, Heuer Direct at 152; *see also* Ex. 14 at Tab A-58.
[1277] Ex. 96, Robinson Direct at 23-25.
[1278] Ex. 439, Lusti Direct at 54.

expenses that were directly associated with the capital projects in the 2015 Step year.[1279] This resulted in a $3.309 million reduction in the 2015 Step revenue requirement.[1280]

762. The Department accepted the $3.309 million reduction in the 2015 Step revenue requirements proposed by the Company.[1281] No other party commented on the issue of property taxes for the 2015 Step year.

S. Emissions Control Chemical Costs (2015 Step) (Issue # 33)

763. For O&M costs for 2015 Step as part of its MYRP, the Company requested an increase over the 2014 budget of $5.959 million for the Minnesota electric jurisdiction, to capture increased mercury sorbent costs due to the addition of emission control equipment at Sherco 1 and 2 in 2014.[1282] The Company's budget was based on the best information available, but the Company acknowledged some uncertainty inherent in estimating the amount of mercury sorbent to be used.[1283]

764. The Department recommended that the Company's proposed increase be reduced by half, to $2.98 for the Minnesota electric jurisdiction, because of the Company's prior over-estimating of the amount of emissions control chemicals and because the chemicals costs at A.S. King and Sherco 3 are not directly tied to new capital upgrades in 2015.[1284]

765. In rebuttal, the Company agreed that non-capital costs in the 2015 Step should be directly related to capital projects and agreed to remove chemical costs associated with A.S. King and Sherco Unit 3 from the 2015 Step (an $180,000 decrease).[1285]

[1279] Ex. 34, Duevel Rebuttal at 12-13; Ex. 98, Robinson Rebuttal at 10; Ex. 100, Clark Rebuttal at 7, 9, 30-32.
[1280] Ex. 98, Robinson Rebuttal at 10.
[1281] Ex. 442, Lusti Surrebuttal at 45.
[1282] Ex. 59, Mills Direct at 39-40; Ex. 96, Robinson Direct at 27-28; Ex. 99, Clark Direct at 16-17.
[1283] Ex. 59, Mills Direct at 40; Ex. 61, Mills Rebuttal at 10.
[1284] Ex. 431, Campbell Direct at 31.
[1285] Ex. 61, Mills Rebuttal at 9-10; Ex. 98, Robinson Rebuttal at 9-10; Ex. 100, Clark Rebuttal at 32; Sparby Rebuttal at 20-21.

766. In response to the Department's continued concern that the budget for mercury sorbent was still too high,[1286] the Company agreed at the evidentiary hearing to further reduce the budgeted amount by $1.4 million, resulting in a total downward adjustment of $1.58 million in revenue requirements.[1287] The Department agreed with this adjustment.[1288] No other parties commented on this issue.

T. MYRP: Rate Moderation Proposal-DOE Settlement Funds (2015 Step) (Issue #34)

767. One of the rate moderation proposals from the Company was to utilize settlement funds[1289] received from the Department of Energy in 2013 and 2014 in excess of the annual decommissioning accrual amount (totaling approximately $35.8 million) to reduce the 2015 Step revenue requirement.[1290]

768. The Department did not oppose use of the DOE settlement funds for rate mitigation in the 2015 Step as these amounts are in excess of the currently approved decommissioning accrual.[1291]

769. The OAG recommended that the Commission carefully consider whether the Company's moderation proposal was reasonable and in the public interest.[1292] The OAG stated that the Company's use of DOE settlement funds does not provide any ratepayer benefit as these are funds owed to ratepayers in any event.[1293]

770. The Commercial Group agreed with the proposal to use excess DOE payments for rate moderation but instead of assigning the entire amount to the 2015 Step, the Commercial Group recommended using the funds received in 2013 to

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1286 Ex. 436, Campbell Surrebuttal at 28-31.
1287 Ex. 140, Heuer Opening Statement. at 7.
1288 Ex. 450, Campbell Opening Statement at 2.
1289 The Company receives settlement payments from the DOE as a result of litigation regarding the DOE's contractual obligation to take spent nuclear fuel. Ex. 95, Robinson Direct at 33.
1290 Ex. 99, Clark Direct at 28-29.
1291 Ex. 429, Campbell Direct at 90.
1292 Ex. 370, Lindell Direct at 16.
1293 Ex. 370, Lindell Direct at 16.

reduce rates in the 2014 Test Year and the funds received in 2014 to reduce rates in 2015.[1294] If the Commission does not approve the 2015 Step, the Commercial Group recommended use of the entire amount to moderate rates in the 2014 Test Year.[1295]

771. During discovery, the Company noted that DOE payments are expected to be $10.1 million lower than projected in the initial filing or $25.737 million.[1296] The Company provided support for this expected reduction to the DOE payments.[1297]

772. During the evidentiary hearing, the Company agreed to true-up and refund to customers any DOE payments received in excess of the amount reflected in the Commission's final Order for the 2015 Step.[1298]

773. Also during the evidentiary hearing, the Department agreed that the current placeholder for DOE payments is now $25.737 million, since the Company had provided support for $10.1 million reduction. The Department stated that this adjustment results in a net $12.633 million increase in revenue in 2015.[1299]

U. MYRP: Refund Mechanism Due to Postponed or Cancelled Capital Projects (Issue #35)

774. During the evidentiary hearing, the Company and the Department agreed to a refund mechanism for capital projects that are postponed or cancelled for the 2014 test year and the 2015 Step.[1300]

775. For the 2014 test year, the refund mechanism will start with the Commission approved 2014 test year plant related base revenue, but exclude the 2014 plant additions for the Monticello LCM/EPU project or 2015 Step projects (Adjusted Test Year 2014 Plant Related Revenue Requirements).[1301] The refund mechanism would then compare the Adjusted Test Year 2014 Plant Related Revenue

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[1294] Ex. 255, Chriss Direct at 12.
[1295] Ex. 255, Chriss Direct at 12.
[1296] Ex. 429, Campbell Direct at 86; Ex. 97, Robinson Rebuttal at 13-14.
[1297] Ex. 130, Perkett Opening Statement at 1; Ex. 450, Campbell Opening Statement at 3-4.
[1298] Ex. 140, Heuer Opening Statement at 7.
[1299] Ex. 450, Campbell Opening Statement at 3-4.
[1300] Ex. 130, Perkett Opening Statement at 1-2.
[1301] Ex. 140, Heuer Opening Statement at 3-4.

Requirements to the actual plant related base rate revenue requirements, again excluding the 2014 plant additions for the Monticello LCM/EPU project or 2015 Step projects (Adjusted Actual 2014 Plant Related Revenue Requirements).[1302] If the Adjusted Actual 2014 Plant Related Revenue Requirements is lower than the Adjusted Test Year 2014 Plant Related Revenue Requirements, the Company will include the amount in the interim rate refund and the calculation of final rates in 2015.[1303]

776. The Company will submit a compliance filing prior to the implementation of final 2014 rates that: (i) calculates the Adjusted Actual 2014 Plant Related Revenue Requirements and compares it to the Adjusted Test Year 2014 Plant Related Revenue Requirements; (ii) compares the 2014 test year to the 2014 actual capital additions, and (iii) provides an explanation for all project capital additions that were included in actual rate base but not part of the 2014 test year.[1304]

777. A similar process will be used in 2015, except it would be limited to only the current proposed 34 Step projects.[1305]

V. MYRP: Compliance for 2015 Step Projects (Issue #36)

778. During the evidentiary hearing, the Company proposed to submit compliance reports to abide by the terms of the Commission's MYRP Order.[1306]

779. The Company agreed to provide quarterly compliance reporting during 2015 (April, August, November) to the Commission comparing the most current forecast of each 2015 Step project to the amount included in the 2015 Step.[1307]

780. By April 1, 2016, the Company will submit its final compliance report which will include: (i) the actual 2015 Step revenue requirement for each project, specifically 2014 actual, 2015 actual and the difference (2015 Step); (ii) the revenue

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1302 Ex. 140, Heuer Opening Statement at 3-4.
1303 Ex. 140, Heuer Opening Statement at 3-4.
1304 Ex. 140, Heuer Opening Statement at 3-4.
1305 Tr. Vol. 2 at 55-56 (Perkett).
1306 Ex. 140, Heuer Opening Statement at 6-7.
1307 Ex. 140, Heuer Opening Statement at 6-7.

requirement difference for each 2015 Step project between the 2015 Step actual and 2015 Step test year; (iii) explanations for project additions that are greater than included in the 2015 Step; (iv) in the event the total actual 2015 Step revenue requirement is lower than the total test year 2015 Step revenue requirement, the Company will include in its compliance filing a proposal for rate refund; and (v) in the event the Company becomes aware of a 2015 Step project cancellation or postponement, the Company will provide 30 day notice including a refund plan.[1308]

W. Service Agreement between NSP and Xcel Energy Services, Inc. (Issue # 37)

781. On March 4, 2014, after the filing of this rate case, the Company filed a petition in a separate docket (Docket No. E,G002/AI-14-234) seeking a second amendment to the Commission-approved service agreement that specifies the methods by which the costs of services provided by Xcel Energy Services, Inc. (XES) are allocated to various accounting function at the Company and to other entities.[1309]

782. The Company and the Department agree that any changes that result from the Commission's order in the service agreement amendment docket will be incorporated into this case as appropriate.[1310]

X. Withdrawal of Hollydale Transmission Project (Issue # 38)

783. The Company noted in discovery that it no longer anticipates that the Hollydale transmission project will be placed in-service during the 2014 test year and proposed to remove the associated capital costs amounting to $388,000 from the rate base.[1311]

[1308] Ex. 140, Heuer Opening Statement at 6-7.
[1309] Ex. 425, Byrne Direct at 3-4.
[1310] Ex. 87, Stitt Rebuttal at 13-14; Ex. 425, Byrne Direct at 4; Ex. 428, Byrne Surrebuttal at 2-3; Ex. 449, Byrne Opening Statement at 1.
[1311] Ex. 437, Lusti Direct at 19-20 and Sch. 31.

784. In Direct Testimony, the Department agreed with the Company's proposal and noted that the proposal results in a $43,025 reduction in revenue requirement.[1312]

785. In Rebuttal Testimony, the Company confirmed withdrawal of the Company's Certificate of Need and Route Permit applications for the Hollydale transmission project and proposed to exclude the associated costs from the 2014 test year, with an associated reduction in revenue requirement of $43,000.[1313]

786. The Department accepted the proposal in Surrebuttal Testimony.[1314]

Y. Prairie Island EPU/LCM Split Correction (Issue # 39)

787. In Direct Testimony, the Company noted results of a recently completed transactional assessment of the Prairie Island EPU/LCM project costs, and indicated had made adjustments to the interim rates and the Company would make the necessary adjustments to the cost allocations in Rebuttal Testimony.[1315]

788. In Direct Testimony, the Department noted the need for this adjustment and indicated preliminary approval based on the Company's adjustment in the Interim Rate Petition.[1316]

789. In Rebuttal Testimony, the Company proposed an adjustment removing $2.157 million from the LCM project costs and reallocating the costs to the EPU portion of the project costs.[1317]

790. The Company's proposed adjustment reduces test year rate base by $1.418 million and decreases test year revenue requirements by $158,000.[1318]

1312 *Id.*
1313 Ex. 100, Clark Rebuttal at 26; Ex. 90, Heuer Rebuttal at 11-12 and Sch. 6A.
1314 Ex. 442, Lusti Surrebuttal at 7-8.
1315 Ex. 88, Heuer Direct at 79; Ex. 12, Notice and Petition for Interim Rates at 9; Interim Rate Petition Supporting Schedules, Schedule B, Part 2, page 5, column 4.
1316 Ex. 437, Lusti Direct at 18-19.
1317 Ex. 90, Heuer Rebuttal at 9.
1318 Ex. 90, Heuer Rebuttal at 9.

791. In Surrebuttal Testimony, the Department agreed to the Company's proposed adjustment.[1319]

Z. Xcel Energy Foundation Administration Cost Correction (Issue # 40)

792. In Direct Testimony, the Company included a reduction to test year rate base of $281,000 to reflect disallowance of all administrative costs of the Xcel Energy Foundation.[1320]

793. In Information Request DOC-1186, the Company identified an error in the original Foundation Administration Cost adjustment and indicated the Foundation Administration Cost adjustment should have included an additional $114,622 reduction in test year revenue requirement related to non-labor Foundation Administration Costs.[1321]

794. The Company proposed the $114,622 reduction in test year revenue requirement in Rebuttal Testimony, and it was accepted by the Department in its Surrebuttal Testimony.[1322]

AA. Big Stone Brookings Cost Correction (Issue # 41)

795. In Direct Testimony, the Company noted that subsequent its original filing, a forecasted update was made to a component of the Big Stone Brookings transmission project, with an effect of lowering the associated test year operating costs.[1323] The Company's initial filing adjusted the interim revenue requirement to reflect the lower operating costs, but did not incorporate the change into the test year revenue requirement.[1324]

[1319] Ex 442, Lusti Surrebuttal at 2-3.
[1320] Ex. 88, Heuer Direct at 10 and 138.
[1321] Ex. 423, Byrne Direct at 6.
[1322] Ex. 90, Heuer Rebuttal at 10; Ex. 427, Byrne Surrebuttal at 3-4; Ex. 442, Lusti Surrebuttal at 31.
[1323] Ex. 88, Heuer Direct at 80.
[1324] Ex. 12, Notice and Petition for Interim Rates at 9; Interim Rate Petition Supporting Schedules, Schedule B, Part 2, page 5, column 5.

796. In Rebuttal Testimony, the Company proposed an adjustment to the test year to reflect the forecasted update.[1325] The Company's proposed adjustment increases test year rate base by $299,000, and decreases test year revenue requirement by $145,000.[1326]

797. In Surrebuttal Testimony, the Department accepted the Company's Big Stone Brookings cost correction.[1327]

BB. Bargaining Unit Wage Increase Correction (2014) (Issue #42)

798. The Company's 2014 test year included a 3.0 percent wage increase for bargaining unit employees.[1328]

799. After the initial filing on November 4, 2013, the union ratified a new agreement with a 2.6 percent wage increase.[1329] To account for this change, the Company proposed a $405,000 reduction to the test year revenue requirements.[1330]

800. In surrebuttal, the Department agreed to the adjustment proposed by the Company.[1331]

CC. Theoretical Reserve for Intangible Plant Correction (Issue # 43)

801. In Direct Testimony, the Company provided a detailed explanation of its amortization of the surplus reserve margin for transmission, distribution, and general assets.[1332]

802. In Rebuttal Testimony, the Company pointed out that in its initial calculations, it had amortized all of the theoretical reserve surplus for intangible plant over eight years, but instead should have amortized the theoretical reserve surplus for electric and common intangible plant accounts over the average remaining lives of

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1325 Ex. 90, Heuer Rebuttal at 40.
1326 Ex. 90, Heuer Rebuttal at 40.
1327 Ex. 442, Lusti Surrebuttal at 12-13.
1328 Ex. 90, Heuer Rebuttal at 41.
1329 Ex. 90, Heuer Rebuttal at 41.
1330 Ex. 90, Heuer Rebuttal at 41.
1331 Ex. 442, Lusti Surrebuttal at 31.
1332 Ex. 89, Heuer Direct at 82-83.

those accounts.[1333] The Company proposed an additional adjustment to fix this error.[1334] The adjustment resulted in a $77,000 decrease in the 2014 rate base and a $28,000 increase in the 2014 revenue requirements.[1335]

803. The Department agreed with the adjustment.[1336] No other party commented on this issue.

DD. Net Operating Loss Correction (2014) (Issue # 44)

804. In its initial filing, the Company provided detailed information about the Net Operating Loss (NOL) in the COSS.[1337]

805. In rebuttal, the Company pointed out that it had inadvertently excluded state tax credits from its initial NOL calculation in the COSS.[1338] The Company proposed additional adjustments to the NOL to fix this inadvertent error.[1339] The adjustments result in a $190,000 increase to the 2014 rate base and a $366,000 reduction in the 2014 revenue requirements.[1340]

806. The Department agreed with the Company's correction relating to the error in NOL.[1341] No other party commented on this issue.

EE. Monticello Cyber Security Correction (Issue # 45)

807. The Company's initial filing included costs associated with the Monticello Cyber Security project, which was scheduled to go in-service during the 2014 test year.[1342]

808. In Direct Testimony, the Company's updated forecasts suggested the Monticello Cyber Security project would be delayed until 2015, and indicated that the

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1333 Ex. 90, Heuer Rebuttal at 41.
1334 Ex. 90, Heuer Rebuttal at 42.
1335 Ex. 90, Heuer Rebuttal at 42.
1336 Ex. 442, Lusti Surrebuttal at 13.
1337 Ex. 89, Heuer Direct at 110-116.
1338 Ex. 90, Heuer Rebuttal at 42-43.
1339 Ex. 90, Heuer Rebuttal at 43.
1340 Ex. 90, Heuer Rebuttal at 43.
1341 Ex. 442, Lusti Surrebuttal at 14.
1342 Ex. 88, Heuer Direct at 80.

Company would make the necessary reductions in test year costs in Rebuttal Testimony.[1343]

809. In Rebuttal Testimony, the Company's updated forecasts projected that the Monticello Cyber Security project will go in service during the 2014 test year, as a result, no adjustments are necessary.[1344]

810. No party other than the Company provided testimony on this issue.

FF. Alliant Wholesale Billing Revenues (Issue # 46)

811. In Rebuttal Testimony, the Company noted that it anticipates receiving a refund from Alliant for transmission expenses paid, which will include $561,616 that will be accounted for in 2014 Other Revenues.[1345] The Company notes no adjustment is necessary because the initial filing includes an adjustment to capture unbudgeted Other Revenues using a three-year historical average and the revenue associated with the Alliant refund will be included in the three-year historical average of Other Revenues in a future rate case.[1346]

812. No party other than the Company provided testimony on this issue.

GG. Cost of Capital Impact (2014 and 2015 Step) (Issue # 47)

813. The cost of capital adjustment is the effect of the change in cost of capital for all other adjustments made to the unadjusted test year.[1347] It is a secondary calculation that cannot be completed until other issues, such as capital structure, cost of debt, return and equity, and overall rate of return are decided.[1348]

814. The Company will update its calculation of the cost of capital to reflect the Commission's final decisions regarding capital structure, cost of debt, return on equity, and overall rate of return in this case.[1349]

1343 Ex. 88, Heuer Direct at 80.
1344 Ex. 90, Heuer Rebuttal at 43.
1345 Ex. 90, Heuer Rebuttal at 44.
1346 Ex. 90, Heuer Rebuttal at 44; *see also* Ex. 88, Heuer Direct at 134.
1347 Ex. 89, Heuer Direct at 145.
1348 Ex. 89, Heuer Direct at 94; Ex. 90, Heuer Rebuttal at 44-45.
1349 [cite needed]; *see also* Ex. 140, Heuer Opening Statement at 3.

HH. Net Operating Loss Impact (2014 and 2015 Step) (Issue # 48)

815. The NSPM income tax determination has been in a net operating loss (NOL) position since 2010.[1350] This means that more deductions exist in the current period than is needed to bring current taxable income to zero.[1351] Excess deductions and unused credits were deferred and tracked for use in future periods.[1352] The Company and the Department developed a process for reporting these deferred balances and returning to customers the revenue requirement reduction associated with the utilization of these deferred balances in the form of a refund or as a reduction to base rates.[1353]

816. Determination of the Company's NOL position is a secondary calculation that cannot be completed until all other adjustments are decided.[1354] In Rebuttal Testimony, the Company analyzed the extent to which various adjustments recommended by the Department, as well as various adjustments recommended by the Company in rebuttal, would reduce taxable income, resulting in less use of the deferred tax asset (and thus increasing the rate base).[1355]

817. The Company agreed that once disputed issues are resolved via issuance of the Commission's final order, the Company will, in a compliance filing, recalculate the NOL to be included in final rates.[1356] The Department agreed that NOL will need to be recalculated.[1357] No other party commented on NOL.

II. Cash Working Capital Impact (2014 and 2015 Step) (Issue # 49)

818. Cash working capital (CWC) refers to the amount of cash a utility needs to have on hand to conduct its business.[1358] A lead/lag study is necessary to

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[1350] Ex. 89, Heuer Direct at 110-11, 144.
[1351] Ex. 89, Heuer Direct at 110-11, 144.
[1352] Ex. 89, Heuer Direct at 144.
[1353] Ex. 89, Heuer Direct at 144.
[1354] Ex. 89, Heuer Direct at 94; Ex. 90, Heuer Rebuttal at 44.
[1355] Ex. 90, Heuer Rebuttal at 44.
[1356] Ex. 89, Heuer Direct at 94; *see also* Ex. 140, Heuer Opening Statement at 3.
[1357] Ex. 442, Lusti Surrebuttal at 14.

determine the amount of CWC that a company must reserve.[1359] Lead time is the number of days between the utility's receipt and payment of invoices it receives.[1360] Lag time is the average number of days between the utility's billing of its customers and its receipt of payment.[1361] In Direct Testimony, the Company calculated its initial CWC requirement.[1362]

819. The Department agreed that the lead/lag factors used by the Company were reasonable.[1363] No other party commented on this issue.

820. Because the CWC calculation is based on the test year O&M expenses and test year rate base, it needs to be recalculated after disputed issues are resolved via issuance of the Commission's final order. In Rebuttal Testimony, the Company calculated the CWC requirement for 2014 based on the various adjustments recommended by the Company at that time.[1364] In Surrebuttal Testimony, the Department calculated the CWC requirement for 2014 and the 2015 Step based on the various adjustments recommended by the Department at that time.[1365]

821. The Company and the Department agreed that CWC will need to be recalculated as part of the final compliance filing based on the revenue requirement approved in this case.[1366]

JJ. Low-Income Renter Conservation Program (Issue #81)

822. The ECC recommended that the Company should implement a low-income conservation program for renters who live in smaller housing units.[1367] ECC stated that there is substantial need and opportunity for promoting energy efficiency

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1358 Ex. 439, Lusti Direct at 24.
1359 Ex. 439, Lusti Direct at 24.
1360 Ex. 439, Lusti Direct at 24.
1361 Ex. 439, Lusti Direct at 24.
1362 Ex. 439, Lusti Direct at 24; Ex. 89, Heuer Direct at 145.
1363 Ex. 439, Lusti Direct at 24.
1364 Ex. 90, Heuer Rebuttal at 46.
1365 Ex. 442, Lusti Surrebuttal at 15, 42.
1366 Ex. 140, Heuer Opening Statement at 3.
1367 Ex. 235, Marshall Direct at 1-31.

in low-income, one- to four-unit rental dwellings, and low-income renters are unable to invest in energy efficiency measures without financial assistance.

823. The OAG agreed with the ECC that low-income renters are one of the groups at most risk being negatively impacted by inclining block rates and would also provide the largest marginal efficiency gains with respect to conservation investment.[1368]

824. The Company noted that it currently offers CIP programs that are also available for low-income renters in smaller housing units through Home Energy Savings Program (HESP) and Multi-Family Energy Savings Program (MESP). The Company is also currently evaluating and redefining its conservation programs and design options for the multi-family segment in the CIP process.[1369] The Company explained that this evaluation will also include addressing the need for program modifications or new programs for one- to four-unit rental properties. The Company agreed to modify its CIP plan once the new program is fully developed.[1370]

825. The Department stated that to the extent that the Company's current programs are available to low-income renters, they should be evaluated and utilized first before creating a new program.[1371] If a need is found to develop an additional CIP program for low-income renters who live in smaller housing units, the Department recommended ordering the Company to work with the Department CIP staff to develop such a program.[1372]

826. In surrebuttal, ECC agreed that the standard CIP process is appropriate for developing and implementing the low-income renter conservation program.[1373]

[1368] Ex. 377, Nelson Rebuttal at 31.
[1369] Ex. 42, Sundin Rebuttal at 16-18.
[1370] Ex. 42, Sundin Rebuttal at 16-18.
[1371] Ex. 416, Grant Rebuttal at 7.
[1372] Ex. 422, Pierce Surrebuttal at 13.
[1373] Ex. 240, Marshall Surrebuttal at 1-3.

Based on these Findings of Fact,[1374] the Administrative Law Judge makes the following:

VIII. CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50 and 216B.08.

2. The public and parties received proper and timely notice of the hearing and the Applicant complied with all procedural requirements of statute, rule, and the MYRP Order.

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of Minn. Stat. §§ 216B.164, 216B.241, and 216C.05.

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.

5. The record supports the resolution of the settled, resolved, and uncontested matters set forth in the above Findings. These matters have been resolved in the public interest and are supported by substantial evidence.

6. Rates set in accordance with this Report would be just and reasonable.

7. The final rates ordered by the Commission should be compared to the interim rates set by the Commission and a refund ordered to the extent that the interim rate exceeds the final rate, subject to any true-up that is ordered.

8. Any Findings of Fact more properly designated as Conclusions are hereby adopted as such.

[1374] Citations to the transcript or hearing exhibits in these Findings of Fact are not inclusive of all applicable evidentiary support in the record.

Based on these Conclusions, the Administrative Law Judge makes the following:

IX. RECOMMENDATIONS

1. The Company is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. The Commission incorporate the agreements made by the Parties in the course of this proceeding into its Order.

3. The Commission adopt the recommendations set forth in the Findings above.

4. The Company make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated on ____________________ ____________________________________

Jeanne M. Cochran
Administrative Law Judge

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 15 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, Metro Square Building, Suite 350, 121 7th Place East, St. Paul, Minnesota 55101-2147. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions of Law and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument with their filed exceptions or reply. Exceptions must be e-filed with the Commission.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.

Certificate of Service

I, SaGonna Thompson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota;

xx by e-mail; or

xx electronic filing.

OAH Docket No. 68-2500-31182

MPUC Docket No. E002/GR-13-868

Dated this 14th day of October 2014

/s/

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SaGonna Thompson

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