414 Nicollet Mall
Minneapolis, Minnesota 55401

September 23, 2014

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

RE: 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 Initial Brief 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 Initial 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 the State of Minnesota	OAH Docket No. 68-2500-31182 MPUC Docket No. E002/GR-13-868

XCEL ENERGY BRIEF

September 23, 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 the State of Minnesota

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MPUC Docket No. E002/GR-13-868

XCEL ENERGY INITIAL BRIEF

I. INTRODUCTION AND OVERVIEW

Northern States Power Company, doing business as Xcel Energy (the Company), provides this Initial Brief in support of its request for an increase in base electric rates.

At the outset, we note that this case may feel similar to our most recent electric rate case because some of the issues are the same (*i.e.*, return on equity, used and usefulness of the Monticello Life Cycle Management/Extended Power Uprate (LCM EPU) Program, and recovery of the 2008 Market Loss as part of our qualified pension expense), and that a significant amount of potential revenue is tied up in a small number of disputed issues. The remaining issues in this proceeding largely have been narrowed to focus on approximately five issues, each of which involves important Company investments to serve customers and can have a significant financial impact of those investments:

- Determining the appropriate rate of return on equity (ROE);
- Determining whether the Monticello LCM/EPU investments are used and useful;
- Determining whether to accept the Department of Commerce's passage of time downward adjustment to the 2015 Step revenue requirement;
- Determining whether to allow recovery of the qualified pension and retiree medical expenses, including the 2008 market loss and a

discount rate for the XES Plan that is consistent with FAS 87 and GAAP accounting; and

- Determining whether to accept the Department's downward adjustment of our total labor costs.

Together, these five issues add up to an approximate $84 million downward adjustment to our 2014 and 2015 revenue deficiencies. For context, these five issues represent about 60 percent of the difference between the Company's request and the Department's recommendation.

Not only is this significant from a revenue perspective, but the outcome on these handful of issues may also affect our ability to conduct our business in concert with rapidly evolving state energy policy goals while continuing to provide safe and reliable electric service to our customers.

For example, accepting the Department's recommended ROE will impact our ability to attract reasonably priced capital during a period of time where we continue to reinvest in our system and make new investments in response to aggressive state energy policies.[1] Further, this could end up being the second consecutive case where our ROE has been reduced. The consequence of these reductions will move our ROE from the lowest quartile of authorized ROEs for vertically integrated utilities to those awarded to distribution-only utilities, or natural gas utilities such as CenterPoint.[2]

The timing of placing the Monticello LCM/EPU project into service serves as another example. Through this case the Company aimed to remove uncertainty around when the remaining program investments could be placed into service from a regulatory accounting perspective. This is important to the Company because the plant is not only a critical aspect of our carbon-free generation portfolio but there is a

[1] Ex. 30, Tyson Direct at pp. 17-21.

[2] Ex 27, Hevert Direct at Sch. 8; Ex. 225, Criss at Sch. 3; *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 (June 9, 2014) at p. 32.

disconnect between our financial and regulatory books which has a financial impact on the Company.[3] The evidence on the record demonstrates the plant is used and useful.[4] Even though the used and useful standard does not require perfect operation of a plant before it can be placed into service, we have agreed to the Minnesota Chamber of Commerce's proposal in an effort to recognize the challenges we have faced during the ascension process. In either scenario, the uncertainty is removed, allowing the Company to move forward without suffering on-going financial harm.

We believe resolution of the remaining issues is critical to understanding whether the Multi Year Rate Plan (MYRP) can be a constructive ratemaking tool for future cases. This is because the Department's proposed downward adjustments to our qualified pension and benefit expenses, and labor costs have a compounding effect, since the Company is not able to recover its actual costs in the test year and Step year; and the passage of time adjustment, which is a new issue that can only arise when multi-year rates are sought, effectively penalizes the Company for not seeking its entire revenue deficiency for the 2015 Step year. If a utility cannot adjust its overall cost of service in the out years of an MYRP, then getting the cost of service correct in the test year is of paramount importance for the MYRP construct to work. Since the evidence on the record demonstrates that we have met all applicable ratemaking standards, the Commission should grant recovery of our qualified pension expense, FAS 106 expense, and labor costs, and reject the passage of time adjustment.

We recognize, however, that we have filed three electric rate cases since 2010. In response, our customers and stakeholders have expressed concern over the affordability and competitiveness of our rates. They also question the sustainability of significant, year-on-year rate increases in the future. In an effort to be responsive to those concerns, as well as state energy policy objectives, we brought forward an innovative rate moderation plan and rate design proposals in this case.

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[3] Ex. 94, Perkett Direct at 43-45.
[4] *Id.*; Ex. 53, O'Conner Rebuttal at 13-14; Ex. 100, Clark Rebuttal at 23-25.

First, our rate moderation plan builds on the Commission's guidance from our last electric rate case where the Commission authorized the amortization of the transmission, distribution and general theoretical reserve.[5] Our plan proposes a faster amortization schedule of the TD&G theoretical reserve, as well as returning to our customers expected Department of Energy refunds today as opposed to at a later time. We structured this proposal in direct response to feedback from our large industrial customers who asked for more predictable and consistent year-over-year rate increases while we cross our investment peak.[6] We believe that this type of innovative ratemaking has merit not only for this case, but provides a blueprint that could be used in future rate cases.

Second, the Company is the first electric utility to propose decoupling its revenues and sales. The goal behind decoupling is to remove the disincentive to promote conservation effort. Similar to our rate moderation proposal, we structured our decoupling plan to provide an opportunity for parties to evaluate the effectiveness of decoupling for an electric utility while being cognizant that we would be the first Minnesota electric utility to implement this complex rate design mechanism. We appreciate the support we received for taking this initial step from our environmental stakeholders; however, the record reflects the interest of some parties to either implement decoupling totally or not at all. We do not believe this needs to be an all or nothing choice as there is a moderated way to roll out and gain acceptance of any innovation, including our decoupling proposal.

The Company is presenting these solutions in the context of another innovative ratemaking tool, an MYRP. The Company structured its request consistent with its interpretation of the Commission's order regarding the MYRP.[7] Specifically, we narrowed our request to focus on specific capital projects and directly

[5] Ex. 99, Clark Direct at 26-30.
[6] Ex. 25, Sparby Direct at 27.
[7] Ex. 99, Clark Direct at 9-117.

related O&M costs in 2015. This means our initially filed request for the 2015 Step was below our 2015 revenue deficiency.[8] At the same time we took the risk associated with our rate moderation and decoupling proposals so that we could achieve not only predictable (just and reasonable) rates but also to further state energy policy objectives.

This case is therefore about obtaining sufficient regulatory support to enable the Company to provide high quality electric service in the future.[9] In this spirit, we have been able to work cooperatively with many parties to resolve several issues, including, notably, sales forecast, property tax, treatment of capital additions, accounting treatment for the Prairie Island Extended Power Uprate project, nuclear fees, emissions chemicals, and active healthcare.[10] While resolution of issues such as nuclear fees, PI EPU and emissions chemicals involved more traditional means of resolving issues through the contested case process, other issues, such as sales forecast and property tax, required more creative resolutions.

With respect to sales forecast, the Company and the Department have agreed to utilize actual weather-normalized sales data to set rates for the 2014 test year.[11] To accommodate the rate case schedule to the greatest extent possible, the Company will provide 11 months of actual sales data by December 16, 2014 and make available resources and schedules the Parties may require to evaluate the data. The Company will also submit its December 2014 actual sales data no later than January 16, 2014, or will submit one month of forecasted data, consistent with the Department's methodology, in its December 2014 filing. With respect to property taxes, the Company and the Department have agreed to a $9 million reduction in property tax expense for the test year, subject to a true up for 2014 based on the Company's Truth

8 Ex. 25, Sparby Direct at 4.
9 Ex. 113, Sparby Opening Statement at 1.
10 Ex. 140, Heuer Opening Statement and Attachment A.
11 Ex. 140, Heuer Opening Statement; Ex. 444, Shah Opening Statement.

in Taxation Notices received in November and December of 2014.[12] The true-up is capped at the $145 million Minnesota jurisdictional level, with no floor on the Company's actual expense. These resolutions help develop a reasonable basis for recovery of the Company's costs of service, and represent a healthy balancing of stakeholder interests.

These were important issues and we appreciate the cooperation of the parties in resolving them. However, to achieve the regulatory support we need to continue to provide safe, reliable electric service that is consistent with the state's evolving energy policies, we need more. Specifically, we believe it is important that the Commission to resolve the five revenue issues discussed above in our favor, and support our rate moderation plan, decoupling proposal, and use of the MYRP consistent with the Company's current position. By doing so, the Commission will send a clear signal that the MYRP construct is a viable ratemaking tool and not a one-time experiment. Since the evidence on the record demonstrates that we have met the applicable ratemaking standards we believe the Commission can provide us the support that we are requesting.

A. Key Revenue Requirement Issues – Executive Summary

The legal standard for establishing electric rates in Minnesota is well known. The Company has the burden to prove its costs are necessary to provide service and are reasonable, that its investments are used and useful, and that the costs included in the test year are representative of actual costs. We believe this burden has been met in this proceeding.

It is important to be clear, however, that the just and reasonable rates standard is not about establishing the lowest possible cost levels. Rather, Minn. Stat. § 216B.16, subd. 6 requires giving "due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue

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12 Ex. 140, Heuer Opening Statement; Ex. 451, Lusti Opening Statement at 2.

sufficient to enable it to meet the cost of furnishing the service…" Put differently, this standard is about supporting the need for adequate public utility service while recognizing that the utility must recover sufficient revenues to support its reasonable investments needed to provide public service.

At the outset, we note that we have presented our most comprehensive case to date with robust supporting detail, testimony, and data. Parties to this case even acknowledged as much.[13] With that said, the key disputed revenue requirement issues in this case are as follows:

	Value of Department Adjustment Compared to Company Request($ in millions)		
Issue	**2014**	**2015 Step**	**2014 and 2015 Step**
ROE	(36.188)	(2.817)	(39.005)
Monticello LCM/EPU Program	(19.059)	7.220	(11.839)
Pension (market loss and discount rate)	(7.945)	-	(7.945)
FAS 106 (market loss and discount rate)	(1.592)		(1.592)
Passage of Time	-	(18.064)	(18.064)
Total Labor	(5.600)	-	(5.600)
Total of Key Issues	**(70.384)**	**(13.660)**	**(84.044)**

We note that on the two largest issues, ROE and Monticello, the Commission's exercise of judgment in achieving the appropriate result is necessary based on unique fact situations presented. The situation is a bit different for the three remaining cost issues. On passage of time; and qualified pension and FAS 106 (market loss and discount rate for both), real costs would be disallowed without any ability to avoid the impacts of disallowances totaling approximately $26 million during the multi-year

[13] Ex. 429, Campbell Direct at 4.

period. There are no facts in dispute that our costs will be higher than what the Department is recommending. The Commission should reject efforts to artificially reduce the costs of service.

With respect to labor costs, which would in essence have a $10 million impact over the two years, there is not a dispute about the substance of the labor costs in 2014. Rather, the dispute, raised for the first time on Surrebuttal, after the Company adequately addressed the Department's initial labor cost concern, is that the level of increase is unreasonable. We have fully documented the reasons for the increase in labor expense. Not unexpectedly a good share is a result of costs of operating our nuclear plants. Like qualified pension, FAS 106, and passage of time, we believe the Commission should reject efforts to artificially limit our legitimate cost of service where there is not a disagreement about the expected outcome.

We briefly summarize our reasoning on each of these issues below,[14] but provide a more detailed assessment of each issue in Section II of this Brief. In addition, Section III of this Brief addresses other disputed matters between the Company and other Parties to this proceeding.

ROE

The question of the appropriate Return on Equity represents the single largest dollar item in the case. Moreover, the nature of the multi-year rate plan and the Company's current investment cycle makes it critical to establish a reasonable ROE that will allow the utility to attract capital at reasonable costs over not just a single test year, but over the two-year term of the multi-year rate plan.

The term of the multi-year rate plan further creates a unique, protracted schedule in this proceeding. By the time the Commission examines the record, the Parties' pre-filed and hearing testimony will be almost eight months old. The timing from initial filing to final rate implementation will likely be over 16 months. As a

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[14] We note that we are not providing citations to the record in the Executive Summary since we provide that information in Section II.

result, the selection of an appropriate ROE depends not only on the market analyses and conditions identified in pre-filed testimony, but also on an appropriate policy approach and common sense judgments.

As noted throughout the Company's case, this is a period in which the Company is crossing the peak of a multi-year investment cycle. It is critical for the Company to obtain a reasonable cost of capital during this period to support the necessary investments. The Company's proposed 10.25 percent ROE is consistent with these goals, and is comparable to the ROEs authorized to other vertically-integrated utilities.

The Department's proposed 9.64 percent ROE in this proceeding causes the Company significant concern. Not only would adopting such an ROE result in a second-consecutive case in which the Company's authorized ROE declined, but a ROE of 9.64 percent would place us in company with gas companies and non-integrated distribution utilities. These types of utilities do not operate generating units, such as our nuclear fleet and rich wind portfolio, or a bulk transmission system subject to stringent federal reliability standards. We believe adopting the Department's low ROE in this proceeding would send a negative signal regarding our regulators' support for utility investments, and create long-term costs for our customers.

Monticello LCM/EPU

The detailed testimony in this proceeding regarding the Monticello LCM/EPU Program establishes that Program assets and equipment are operating and serving customers, providing a safer, modernized, more efficient facility. It is also undisputed in the record that Monticello now has all license amendments needed to operate at uprate levels, has achieved a partial ascension from 600 to 640 MW, and is expected to fully ascend to 671 MW by the end of 2014.

As a result of the challenges the Program has faced and delays in achieving full ascension, various Parties offered proposals in this proceeding for rate case treatment of the EPU aspect of the combined LCM/EPU Program. The Company supports the Minnesota Chamber of Commerce (Chamber) proposal to remove depreciation and direct expenses related to the Monticello EPU from the 2014 test year and amortize them over the life of the facility, while also removing increased replacement fuel and power costs for recovery over the life of the facility. This approach strikes a middle ground between placing the entire facility in service at the beginning of 2014 and the Department's all-or-nothing test, which assumes the plant must fully ascend to 671 MW to be considered "used and useful." As the more moderate proposal, the Chamber's approach reasonably reflects the benefits of the Program and takes into account that the delay in achieving full ascension is not due to licensing or safety issues, but rather data issues the Company is assessing for the NRC.

If the Commission does not adopt the Chamber's proposal, the Monticello LCM/EPU Program should be considered fully used and useful in 2014. We discuss the used and useful standard, noting that it does not require maximum benefit achieved from the assets at the time the decision to allow rate recovery is made. Rather, the assets simply must be in use and reasonably necessary to the provision of utility service during the test year or period rates are in effect. As noted, it is uncontested that, unlike in our prior rate case, all license amendments have been received, partial ascension has been achieved, and full ascension is expected during the period rates will be in effect. Moreover, unlike our last rate case (when at the time of evidentiary hearings, we were still in an extended outage related to the LCM/EPU), in this case all assets serving the combined LCM/EPU program are presently operating in service of customers. These circumstances warrant considering the Monticello assets "used and useful" for purposes of this rate case and because of this, make the Chamber's proposal and our acceptance of it a reasonable approach which should be approved.

Passage of Time

The Commission's 2013 Multi-Year Rate Plan Order requires, in part that multi-year rate plans must be designed to recover the costs of specific, clearly-identified capital projects and, as appropriate non-capital costs. The Company's 2015 Step request is consistent with this requirement, as it includes only a limited number of specific capital projects and certain non-capital costs. As such, the Company's 2015 Step request is significantly lower than the Company's actual, total 2015 revenue requirement and includes all components of a limited number of capital projects.

Nonetheless, the Department proposed a "passage of time" adjustment that would reduce the Company's 2015 revenue requirement to reflect changes in the Company's depreciation reserve and expense between 2014 and 2015 for all capital assets not already included in the 2015 Step. This adjustment should be rejected as inconsistent with the Commission's 2013 Multi-Year Rate Plan Order limiting the scope of the Step to specific capital projects. It is also inconsistent with the concept of symmetrical ratemaking, as it expands the scope of the 2015 Step to recognize solely depreciation for non-Step projects. Perhaps most fundamentally, when the "passage of time" adjustment is calculated to include both accumulated depreciation reserve and depreciation expense, the adjustment would actually increase the Company's Step revenue requirement, rather than decrease it by approximately $17 million as proposed by the Department. On this last point, an incomplete answer led us down a path of disagreement that simply should not exist. The Department issued discovery asking the Company for the impacts on rate base *and* depreciation expense for annualizing 2014 non-step projects into 2015. While we incorrectly answered the information request by only providing the rate base component, we provided all of the requested information in our rebuttal testimony where we provided the accumulated depreciation reserve and depreciation expense. Further, we clarified that the combination of rate base and annualized depreciation expense (which significantly increases in 2015) would actually increase the cost of service.

Rather than moving off the list of adjustments, the Department has stood firm, disagreeing with our policy concerns and effectively ignoring the math. For each of these reasons, the Department's passage of time and asset retirement adjustments for the Step should be declined.

Pension

As in our prior rate case, the calculation of pension expense is a matter of dispute between the Company and the Department. The two primary issues in this case relate to recovery of the Company's 2008 market loss, and establishing the discount rate for the XES plan.

As it pertains to the 2008 market loss, it is undisputed that the Company's calculation of pension expense for the NSPM and XES plans is based on methodologies that have been approved by the Commission and consistently applied for many years. Due to the unique nature of a pension benefit, these methodologies incorporate prior experience into the calculation of actual expense each year. Part of that experience is the fact that our pension plan along with every other plan, experienced substantial losses in 2008. The so-called 2008 market loss adjustment is simply the reflection that the plan after 2008 had substantially fewer assets, and therefore higher pension expense. For this test year, we continue to maintain the same course to calculate the Company's pension expense. Our test year pension expense includes some amount that if traced can be attributable to the 2008 market loss. We also experienced increases in expense due to lower interest rates, which has a benefit in other aspects of the cost of service. We demonstrated that we calculated our expense correctly and that this retirement benefit, along with the others offered by the Company, is consistent with market levels. No party offered any evidence to suggest that our pension expense is not representative of our actual expense, or that a pension benefit is not a reasonable cost of service. Here again, there is no reason for disallowance of legitimate costs of service.

Similarly, the Company's discount rate calculation for the XES Plan is based on long-standing principles by using both Aggregate Cost Method and Financial Accounting Standard 87 to calculate the impact of the discount rate on the NSPM plan and the XES plan. Unlike most Minnesota utilities, the use of Aggregate Cost Method equalizes the EROA and discount rate for 75 percent of our pension expense and provides for a lower pension expense than if both plans were on Aggregate Cost. As such, the Company has already returned most of the benefit sought by the Department in its test year pension expense. Using the FAS 87 discount rate for our XES plan ensures the Company's cost recovery matches its actual costs of providing this important benefit to utility employees. The evidence on the record demonstrates that the discount rate the Company uses for the XES Plan is representative of actual financial market rates. Additionally, as noted above, we believe it is symmetrical for our expense calculations to use the same types of discount rates as we are obtaining for our cost of capital. Meaning if our customers are benefiting from current interest rates then our expense calculations should be equally reflective.

Total Labor

The Department has proposed an adjustment to the Company's total test year labor costs based on an historical trend of 2012 labor costs and the unsupported assumption that labor costs should increase no more than 3 percent year over year. The Department's analysis contains no assessment of the reason the Company's labor costs increase more than 3 percent for the 2014 test year, whether those increases are justified by the underlying needs of the Company, nor whether the 2014 test year costs are representative of the Company's actual costs. Oddly, this adjustment arose when the Company responded to concerns that paid leave (which is a component of total labor) was under budget for the three previous years. The Company showed that people simply did not take all of their vacation time and that our labor costs were slightly over budget for the past three years. In responding to this concern in our Rebuttal testimony, the Department changed directions, and imposed its 3 percent reasonableness cap. In contrast, each of the Company's core Business Area witnesses provided a discussion of his or her O&M budget including labor costs, as well as detailed explanations for cost trends and increases. No party challenged that the Company will incur these costs, nor that the Company needs to incur these costs to conduct its business. Subsequently, in response to the Department's proposed adjustment the Company identified the Nuclear and Business Systems areas as the drivers of the Company's total labor cost increases above 3 percent, and pointed to the specific Company witness testimony explaining why these costs are reasonable and necessary.

The test year concept does not allow for arbitrary caps on costs the utility reasonably incurs to provide utility service to customers. Rather, the Company has met its burden to establish the need for these costs and the reasons they are reasonable given the current labor needs of the Company in order to provide quality electric service. Accordingly, the Department's total labor adjustment is neither warranted nor supported in the record.

Summary

Although there are significant differences in the recommended results for this case, those differences are concentrated in just a few, very substantial issues. The ALJ and Commission have well-established standards and guidelines to apply to these issues that help clarify the important and relevant facts and the treatment that should be afforded to ensure these standards are met. When doing so, the Company believes it is clear that we have met our burden of demonstrating that our costs are legitimate and necessary for providing electric service and that our proposed treatment is consistent with the Commission's past practice. In the subsequent sections, we first address each of the five key issues, highlighting the relevant facts and applicable legal principles that should be applied when considering them. We then provide our brief on the remaining revenue requirement disputed issues, and rate design.

II. KEY DISPUTED ISSUES

A. ROE (Issue # 1)

Establishing the correct ROE is a critical part of every rate case. In this case, this is especially true because the Company is crossing the peak of its capital investment cycle, as part of a multi-year rate plan during a period of prolonged market volatility. While the Company has not earned its authorized ROE in recent years,[15] "[h]aving the opportunity to earn a return that is adequate to attract both debt and equity capital at reasonable terms, under varying market conditions, will enable the utility to provide safe, reliable electric service while maintaining its financial integrity."[16] The practical implications of the Company's ability to attract capital and retain its financial integrity are even more pronounced considering continued capital market instability and sustained increase in interest rates.[17]

From another, but related perspective, the ROE authorized by the Commission is a communication to our investor community. Specifically, when the Commission authorizes a ROE for the Company which is consistent with (and, when appropriate, higher than) other large, vertically integrated utilities, the signal that is sent is that our capital investments are supported and consistent with the State's public policy. For that reason, the Company believes the Commission should (and has the discretion to) authorize a ROE which furthers the energy policy goals of the State and, thus, result in just and reasonable rates.

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[15] Ex. 30, Tyson Direct at 14-15.
[16] Ex. 27, Hevert Direct at 7:24-8:2.
[17] Ex. 27, Hevert Direct at 8:2-9.

The Company and several intervening parties, including the Department, have presented ranges a potential authorized ROE. The Company's analysis supports our requested 10.25 percent ROE. The Company believes there are significant technical deficiencies with the analyses supporting the recommendations of the ICI Group, the Commercial Group and AARP. We present our reasoning in detail below. We note, however, that the Department has provided a consistently applied sophisticated analysis; as a result we focus on its analysis which has resulted in their recommended 9.64 percent ROE. While we believe that the 10.25 is more reflective of the business risks we face in a rapidly changing environment, at a minimum, the Commission, should in any event, not again reduce our authorized ROE in the midst of significant investments in our infrastructure and clean energy projects.

We recognize that the Commission generally has adopted the Department's recommendation in recent rate cases. With that said, however, we believe there are three circumstances surrounding this rate case which are unique enough to support a change in course: (1) this is a MYRP and not a traditional rate case and there is a longer time lag between Commission's authorization and last updated ROE analysis; (2) recognized prolonged financial market volatility; (3) the comparable ROEs recommended are approaching those of gas and distribution only electric companies and no longer reflect the risk of vertically integrated electric utilities; and (4) it is in our customers' interest not to erode the ROE during a period of major capital expansion as investors lose confidence that the Commission is supportive of the investments we are making to continue to provide safe and reliable service, consistent with the State's evolving energy policies.

The Company is presenting the Commission with a multi-year rate plan and not a traditional one-year rate case. This means that the ROE authorized by the Commission will affect at least a two-year rate period and not just the single test year of a traditional rate case. As the Company explained, the ROE needs to be set at a level that is sufficient so that the Company can absorb the longer term financial market risk than presented by a traditional rate case.[18] Therefore, the Company believes its use of a MYRP supports a higher than usual authorized ROE.[19]

Further, due to the significantly longer period of time between the Commission's deliberation and the last updated analysis on the record during an MYRP, there is the potential that relevant financial market changes will not be reflected under the Commission's traditional methodology for selecting an authorized ROE. For a traditional rate case, Minnesota law requires the Commission to issue its decision within 10 months of the utility filing its request. Using our last electric rate case as a benchmark, the Commission deliberated on our request within four months of the last updated ROE analysis on that record. By way of comparison, the procedural schedule in this case could take approximately 50 percent longer. Meaning there will be even more time between the last updated ROE analysis and the Commission's deliberations. We believe this is significant in light of the prolonged market volatility described on this record and the expectation of rising interest rates.

In addition to these unique circumstances, adopting the Department's recommendation of a 9.64 percent indicates that our business is more analogous to a distribution only utility, and/or a natural gas only utility. By way of context, the evidence on the record demonstrates that 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.[20] Furthermore, the Commission recently authorized a 9.59 percent ROE for Centerpoint,[21] and the ALJ recommended

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[18] Ex. 27 (Hevert Direct) at p. 52-53.

[19] Ex. 27 (Hevert Direct) at p. 52-53 (discussing the effect of market volatility on establishing a ROE for a MYRP).

[20] Ex. 225, (Chriss Direct, Schedule 3).

[21] *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. GR-13-316, Findings of Fact, Conclusions, and Order (June 9, 2014) at p. 32.

a 9.79 percent ROE for MERC.[22] We believe this is noteworthy because the business risks posed to distribution only utilities and natural gas utilities are quite different than those presented by our business. For example, the Company operates two nuclear generating plants which are subject to significant federal regulatory oversight; has a large transmission system which is subject to the stringent federal bulk electric system reliability requirements; and is deploying capital to support the State's energy policy to reduce carbon emissions.

By establishing our ROE at our requested level, the Commission will be signaling to the investment community that it has taken these issues into account and is supportive of our investments to provide safe and reliable electric service while meeting the State's evolving energy policies. When taken together we believe these considerations support authorizing a ROE of 10.25 percent. But we acknowledge that an authorized ROE of 9.83 percent could be appropriate to the extent the Commission is interested in finding a middle ground.

1. Standards for Determining ROE

The established standards for determining the return to be awarded are clear. Minn. Stat. § 216B.16(6) establishes that a utility's revenues should enable the utility to "earn a fair and reasonable return upon the investment" it has made in property used to provide service. The applicable standards include a comparability to the return available from investments in other enterprises with corresponding risks, and sufficiency to maintain financial integrity and attract capital.[23] Comparability of returns is not a substitute for a return that is sufficient to attract capital.

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[22] *In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. 8-2500-31126/GR-13-617, Findings of Fact, Summary of Public Testimony , Conclusions of Law and Recommendation (Aug 12, 2014) at p. 24.

[23] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944):

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

2. The Record Supports a ROE of 10.25 Percent

A number of factors support a 10.25 percent return on equity (ROE) and show that reducing the ROE below the currently authorized 9.83 percent would cause significant harm. These factors include:

- Current financial market volatility, including unusually high valuations in utility stock prices in the first half of 2014, with utility stock prices now falling and with projected interest rate increases;
- The two-year period during which the ROE will be in effect; and
- The Company's extensive ongoing capital expenditures ongoing need to fund those expenditures with equity investments and debt issuances.

Further, both a 10.25 percent ROE and the currently authorized 9.83 percent ROE are within the Department's Discounted Cash Flow (DCF) range for the Final Electric Comparison Group. Accordingly, the Company recommends that the Commission adopt an ROE of 10.25 percent.

3. Updated DCF Results Incorporate Unsustainable Utility Stock Levels

The updated DCF analyses of the Company and Department were undertaken at a time when utility stocks were trading at aberrantly high levels especially considering long-term expectations for financial market performance indicators such as interest rates. This means both analyses found utilities to be lower risk and in need of perhaps a lower ROE than may actually bear out during the next two years. When one considers that the Department's most updated results is based on a one month snapshot of the financial market during this period of non-representative market behavior but this MYRP takes place over 24 months, the Company believes it is appropriate to authorize a ROE that is more aligned with its requested 10.25 percent ROE.

The Department originally recommended an ROE of 9.80 percent, the midpoint of a range of 8.97 percent to 10.62 percent, based on a 60 percent/40 percent weighting of the Dr. Amit's Final Electric Comparison Group (FEGC) and Final Combination Comparison Group (FCCG). In Surrebuttal, the Department recommended a 9.64 percent ROE, the midpoint of the updated range of 8.90 percent to 10.39 percent, based on an updated DCF analysis (for June 7, 2014 to July 7, 2014) and adjustments to the FEGC and FCCG.

The Company initially recommended an ROE of 10.25 percent, based on a range of 10.00 percent to 10.70 percent, with an 80 percent/20 percent weighting of electric and combination company comparable groups. In Rebuttal Testimony, the Company maintained its 10.25 percent ROE recommendation and range of 10.00 percent to 10.70 percent with data updated through May 30, 2014.[24]

Both the Company's and the Department's updated DCF results reflected decreases in dividend yields. The dividend yield for Dr. Amit's FEGC fell by 54 basis points and the dividend yield for his FCCG fell by 26 basis points from Direct to Surrebuttal testimony. The dividend yields fell 34 basis points for Mr. Hevert's Electric group and 48 basis points for his Combination group from Direct to Rebuttal testimony.[25]

These significant and sudden decreases in dividend yields were the result of increases in utility stock prices.[26] During the first half of 2014, utility stocks traded at unusually high valuation levels when the utility sector's Price/Earnings ratio was generally equal to, if not somewhat greater than, the overall market Price/Earnings ratio. This situation was the opposite of the normal situation in which utility Price/Earnings ratios are less than the market Price/Earnings ratio.[27] The Constant Growth DCF model assumes that Price/Earnings ratios will remain constant in perpetuity.[28] As a result, whether the unusually high valuation levels observed during

[24] Ex. 28, Hevert Rebuttal at 1-2.
[25] Ex. 115, Hevert Opening at 2.
[26] Ex. 115, Hevert Opening at 2.
[27] Ex. 115, Hevert Opening at 2.
[28] Ex. 27, Hevert Direct at 31.

the first half of 2014 will continue becomes significant. Further, indications are that utility stock prices are returning and will return to more typical (lower) levels.[29]

Investors expect increased interest rates over the coming two years. That expectation can be seen in higher projected Treasury yields, in the prices that investors are willing to pay for the option to sell long-term Treasury bonds in the future, and in the interest rate forecasts[30] Since early July, 2014, utility stock prices have declined relative to the overall stock market. The decline in utility stock valuations is consistent with the market expectation of increasing interest rates over the coming two years and consistent with a return to more typical utility stock valuations to historical norms from the very high and likely unsustainable levels reflected in the updated DCF results of both the Department and the Company.[31]

4. Substantial Capital Investments and Market Confidence

The Company remains in a period of very substantial capital investment, which began in 2005 and will continue through 2017. Capital markets are concerned with the level of regulatory support during such periods and another reduction in the Company's authorized ROE will be likely to have an adverse impact on investors and increase the Company's long-term cost of capital as the Company accesses capital markets to raise the funds needed to complete this program.

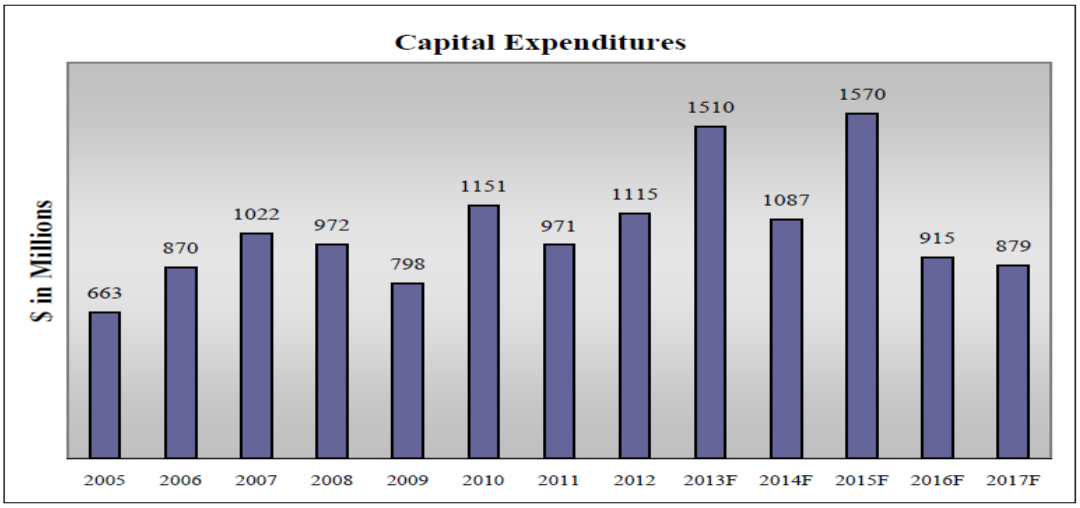
The high levels of the Company's previous and projected capital expenditures are apparent. The Company has invested approximately $7.6 billion from 2005

[29] Ex. 115, Hevert Opening at 2.

[30] Ex. 115, Hevert Opening at 3; Ex. 27, Hevert Direct at 11-12; ; Ex. 30, Tyson Direct at 17; Tr. Vol. 1 (Hevert) at 100-101 and page 100, lines 7-9 "[W]hat we see is that investors expect long-term interest rates to increase over the next two years." Page 100, line 20 to page 101, line 5 "[W]hat we see … is, again, an expectation of increasing interest rates in the future. That is, I think, the important point; that as we look forward, especially again in a situation in which you have effectively a two-year period during which the Company will not be seeking rate relief, it's important to understand whether or not the market expects capital costs to be rising during that period."

[31] Ex. 115, Hevert Opening at 2.

through 2012 and projects additional capital expenditures averaging slightly less than $1.2 billion per year from 2013 through 2017,[32] as follows:



Investments through 2012 included the MERP projects, wind generation, nuclear Life Cycle Management and the Monticello extended power uprate, and transmission and other infrastructure.[33] To fund investments through 2013, the Company has currently outstanding approximately $4.2 billion in long term debt,[34] 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.[35] The Company will continue to invest capital, and it is quite likely that it will do so as the cost of capital is rising and as it needs access to the capital markets.[36]

The projected expenditures will be needed to complete the CapX2020 transmission project, the Prairie Island Unit 2 steam generator replacement, and several transmission and distribution infrastructure replacement projects.[37] These

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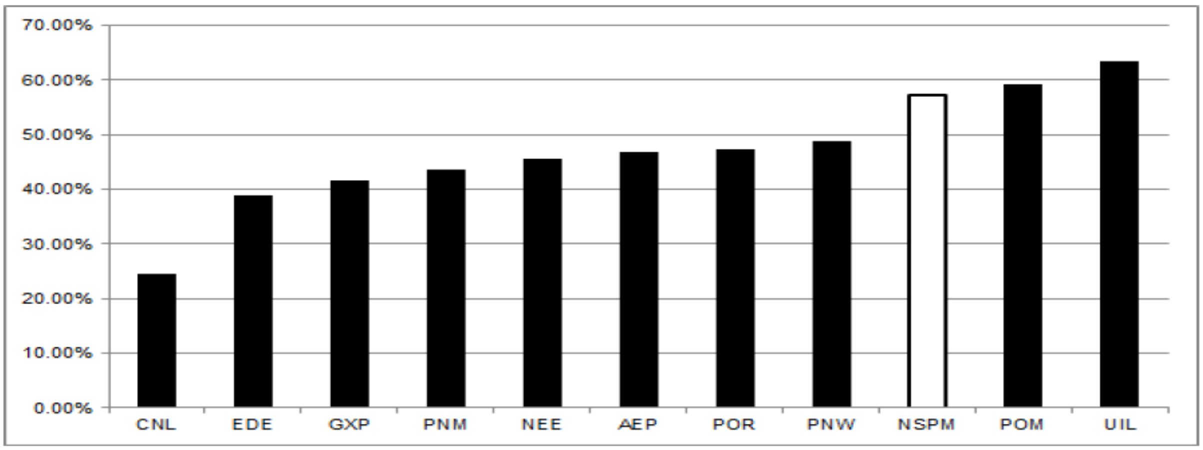
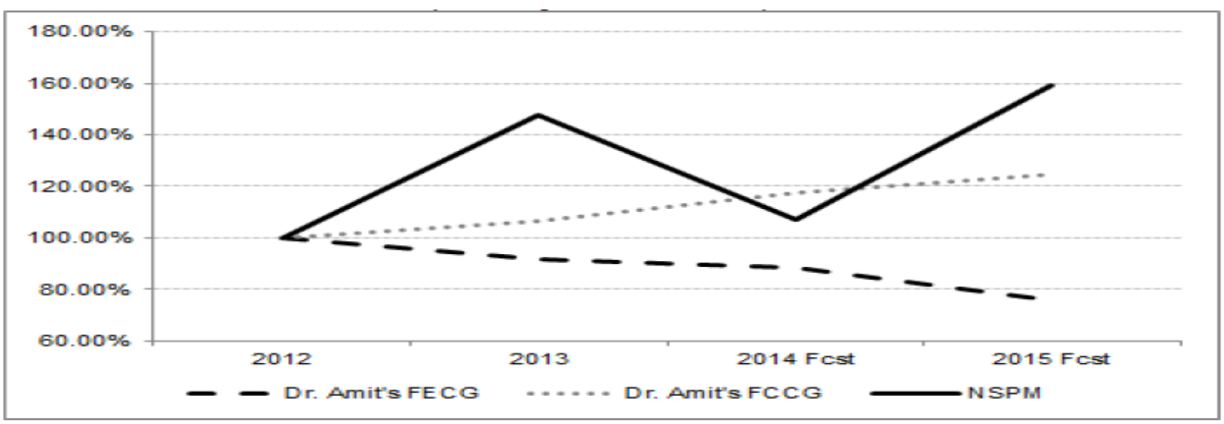
32 Ex. 30, Tyson Direct at 5, 14, 15 and Schedule 3.
33 Ex. 30, Tyson Direct at 14.
34 Ex. 31, Tyson Rebuttal at 5.
35 Ex. 31, Tyson Rebuttal at 13.
36 Ex. 30, Tyson Direct at 16; Ex. 31, Tyson Rebuttal at 10.
37 Ex. 30, Tyson Direct at 16.

capital expenditures are needed to meet reliability standards and other compliance requirements and to support the infrastructure necessary to serve the Company's customers.[38]

Not only are these expenditures large in an absolute sense, they are at the top of the range of comparable electric utilities as shown below:[39]



The Company's projected capital expenditures are even higher in relation to Dr. Amit's comparable groups as shown below:



The Company will need regular access to capital markets to fund these levels of capital expenditures.[40] The Commission has historically provided a stable and predictable approach to the significant financial issues associated with ROE, capital

38 Ex. 30, Tyson Direct at 5.
39 Ex. 28, Hevert Rebuttal at 11.
40 Ex. 30, Tyson Direct at 16.

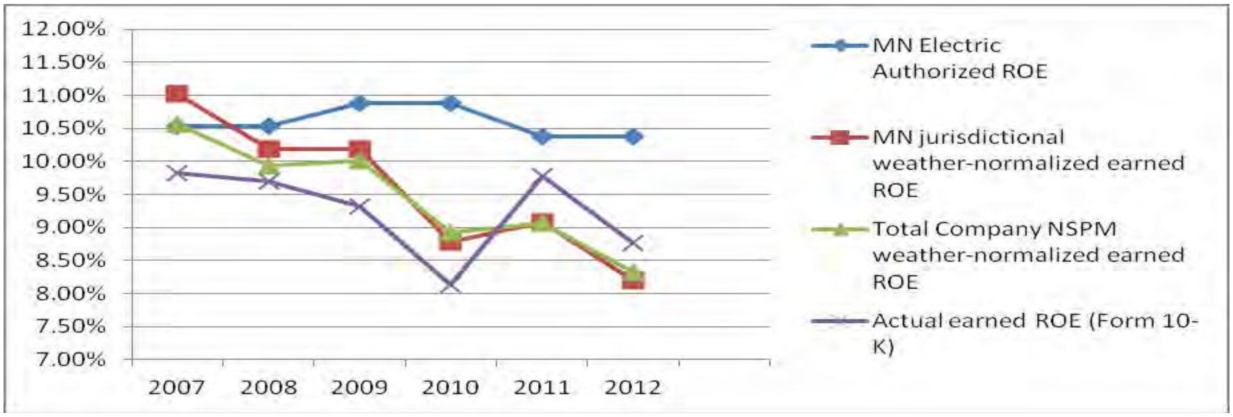
structure, and cost of debt that have supported the Company's ability to raise needed capital at favorable rates.[41] Specifically, the level of regulatory support that the Commission has provided in prior years has significantly assisted the reduction in the Company's cost of long term debt (LTD) to the lowest level since 2000.[42] Continued regulatory stability, including a reasonable ROE, is needed to obtain the lowest possible cost of capital, and the best possible access to capital, both of which will provide long lasting benefits to customers. While we recognize that our investments are impacting customer rates, the Company has offered a mitigation plan to address these rate impacts. To the extent that the Commission is balancing concerns about a higher ROE and the impact on customer rates, we believe that it achieve that balance, not by lowering the ROE but by considering further mitigation to the extent needed.

5. ROE Erosion and Regulatory Environment

Since the regulatory climate is one of the principal investment risk factors for a regulated utility, the Commission's rate case decisions are of particular importance to our debt and equity investors, which is enhanced during periods of significant investment.[43]

As explained above, the Company has been in a period of very substantial capital expenditures. Unfortunately, during much of the same period, the Company has been unable to earn a reasonable ROE, much less its authorized ROE, shown below:[44]

41 Ex. 30, Tyson Direct at 20.
42 Ex. 30, Tyson Direct at 5.
43 Ex. 30, Tyson Direct at 6.
44 Ex. 30, Tyson Direct at 15, Chart 1.



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.[45] This pattern of high capital expenditures and unreasonably low earned ROEs has significantly affected the Company's need to submit rate case filings that have been more frequent than the Company preferred.[46]

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.[47]

The Commission's decisions are of primary importance to investors and credit rating agencies. Investors and credit rating agencies are aware that NSPM has investments that are very heavily weighted toward its electric business. They are also aware that NSPM's customers are concentrated in Minnesota, making the Minnesota retail electric jurisdiction NSPM's primary jurisdiction. Rating agencies and bond and equity investors also know that the Commission is fully informed about NSPM's

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45 Tr. Vol. 3 (Heuer) at 167.
46 Ex. 30, Tyson Direct at 15.
47 Ex. 30, Tyson Direct at 23.

investment plans. As a result, they will likely consider the Commission's decisions in this case as a reflection of the level of support for those investment plans.[48]

Specifically, authorizing a low ROE when compared to other states (such as a reduction from the current 9.83 percent to the Department's Surrebuttal recommendation of 9.64 percent) would send a clear and negative signal to investors that the Minnesota regulatory environment is not supportive of the Company's capital expenditure program. 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 percent and 9.64 percent would have a disproportionately negative effect.[49]

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. 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. That ROE erosion during a period of continuing capital investments, changing market conditions, and expected increases in capital costs, would suggest an increase in regulatory risk in Minnesota that could well increase the cost of capital in the near and long term.

6. Importance of Two-Year ROE Term

The minimum two-year duration of the Commission's ROE decision in this proceeding also imposes added uncertainty as a result of the current unstable capital market conditions. Further, the two-year term of the ROE decision in this case is particularly important because investors believe that long-term rates are likely to

[48] Ex. 30, Tyson Direct at 18-19.
[49] Ex. 115, Hevert Opening at 4.

increase during the next two years, representing a significant element of risk for equity investors.[50] There are several sources of uncertainty.

The uncertainty associated with Federal Reserve policy (the unwinding of the quantitative easing stimulus program) represents a meaningful risk to investors in general and a greater risk to investors in debt and equity securities of electric utilities.[51] While current interest rates have remained low, the market clearly expects interest rates to increase in the future.[52] As interest rates increase, prices for utility stocks would be expected to decline, suggesting an increase in the cost of equity, even though they do not move in lockstep with interest rates.[53] In addition, any unwinding of quantitative easing would be likely tied to improving economic conditions, leading to higher growth estimates, including the utility sector. Since companies such as NSPM continue to invest in their rate base, it would not be surprising to see an increase in expected utility growth rates.[54]

Further, it is clear that the interest rate environment has changed, and continues to change, since the Company's last rate filing. In particular, both current and expected interest rates have risen significantly, and have been quite volatile over the past several months. As a capital-intensive company that requires continual access to external sources of funds, NSPM is exposed to the increased risks and costs resulting from the market conditions.[55] These risks are heightened by the two-year effect of the ROE decision in this case.

If the Company is unable to recover increases in its market-required cost of equity during a period of rising interest rates and increasing price instability, investors

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50 Ex. 27, Hevert Direct at 52.
51 Ex. 27, Hevert Direct at 10-11.
52 Ex. 27, Hevert Direct at 10-11; Ex. 115, Hevert Opening at 3.
53 Ex. 27, Hevert Direct at 13-14.
54 Ex. 27, Hevert Direct at 14.
55 Ex. 27, Hevert Direct at 15.

necessarily will incorporate a larger risk premium to reflect the risk which would support a premium to the current cost of equity.[56]

7. Consistency with Past Commission Practices

Mr. Hevert and Dr. Amit followed Commission practices and both based their recommendations on:

- Screening criteria for their electric utility and combination utility comparable company groups, although the screening criteria used were not identical;
- The DCF model, with both Mr. Hevert and Dr. Amit using a combination of the constant growth DCF model and a Two-Growth DCF model;
- The use of earnings projections from multiple sources to determine growth for the DCF model;
- The recovery of flotation costs; and
- The use and weighting of two comparable groups, one group of pure electric companies and a group of combined gas and electric companies like the Company, although Mr. Hevert applied a 80 percent/20 percent weighting to the electric and combination comparable groups and Dr. Amit applied a 60 percent/40 percent weighting.

Mr. Hevert and Dr. Amit also agreed that no adjustment to the Company's ROE was appropriate in regards to either decoupling or including Construction Work in Progress (CWIP) in rate base.

Mr. Hevert and Dr. Amit presented well documented explanations of how they selected the companies for their electric utility and combination utility comparable groups. These criteria were similar to criteria that the Commission has accepted in the past.

Contrary to their well explained criteria, Mr. Glahn's Direct Testimony did not reasonably explain how he selected his comparable companies, and he was unable to

[56] Ex. 27, Hevert Direct at 52-53.

do so in response to questions from the Department. The absence of a reasonable explanation of his comparable group is a sufficient reason to give his recommendation no weight.

The Commission typically relies on the DCF model in making its ROE determinations and has accepted the use of a combination of the constant growth DCF model and the Two-Growth DCF model.[57] Both Mr. Hevert and Dr. Amit used the same form of the Two-Growth DCF model.[58]

The Commission has also consistently accepted the use of analysts' earnings growth projections to determine the growth component of the DCF model.[59] Both Dr. Amit and Mr. Hevert relied on analysts' earnings growth projections from multiple sources because multiple sources establish reliable data to estimate earnings growth.[60] Contrary to this consistently accepted approach, Mr. Glahn applied four growth estimates that were from a single source (Value Line) and an approach (i.e. "sustainable growth") that has not been accepted by the Commission in any prior Company rate case.[61] Analysts and investors focus on earnings growth, which indicates that earnings growth is the appropriate measure for the DCF model.[62] Prior research indicates that investors rely on analysts' earnings growth projections in valuing equity securities.[63] Historical market data and independent research also indicate that Mr. Glahn's sustainable growth model is unreliable.[64]

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[57] Ex. 27, Hevert Direct at 30; *Petition of Xcel Energy,* Docket No. E-002/GR-12-961, Findings of Fact, Conclusions of Law, and Order (September 3, 2013) at 11-12.
[58] Ex. 38, Hevert Rebuttal at 6-7.
[59] *See, e.g. Petition of Xcel Energy,* Docket No. E-002/GR-12-961, Findings of Fact, Conclusions of Law, and Recommendations (July 3, 2013) at Order 77-78, 82; Findings of Fact, Conclusions of Law, and Order (September 3, 2013) at 11-12.
[60] Ex. 38, Hevert Rebuttal at 6-7.
[61] Ex. 28, Hevert Rebuttal at 33.
[62] Ex. 28, Hevert Rebuttal at 36.
[63] Ex. 28, Hevert Rebuttal at 38, citing Roger A. Morin, PhD, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 298-303.
[64] Ex. 28, Hevert Rebuttal at 37.

Both Mr. Hevert and Dr. Amit also used the Commission approved method to determine flotation costs, including taking into consideration sources of equity for which the Company does not incur flotation costs.[65] No other party addressed flotation costs.

Both Mr. Hevert and Dr. Amit weighted the results of their respective electric and combination comparable groups, although the weightings differed. While this issue is significant, it has much less impact than the prices of the utility stocks which result from the time periods selected to gather data.

Mr. Hevert recommended an 80 percent/20 percent weighting of the electric and combination company groups. Applying those weights leads to a weighted-average of total operations (based on relative operating income) that is similar to the Company. Specifically, on a weighted average basis, electric utility operating income (for the two proxy groups) represents approximately 91.00 percent of total regulated income. 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).[66]

Dr. Amit's FECG includes companies which, on average, derived 90.00 percent of their net income from regulated electric utility operations. Consequently, Dr. Amit's FECG already incorporates companies that reflect proportions of regulated electric operations that are highly consistent with NSPM.[67] Any further weighting of non-electrical operations (through Dr. Amit's FCCG) would be disproportionate, especially since this proceeding is directed solely to electric rates.

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. The AARP stated that a number of utility

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65 Ex. 27, Hevert Direct at 38; Ex. 28, Hevert Rebuttal at 8; Ex. 400, Amit Direct at 32-33.
66 Ex. 27, Hevert Direct at 21.
67 Ex. 28, Hevert Rebuttal at 19.

Commissions have decided to lower ROE because of decoupling. Both Dr. Amit and Mr. Hevert disagreed with this recommendation. However, the AARP's recommendation is based on a selective and slanted review of decisions by other commissions, ignoring the fact that most commissions do not make an adjustment for decoupling.[68] Further, Dr. Amit noted that the issue is how the Company compares to the comparable companies, not how decoupling may affect the Company on a stand-alone basis, citing a Brattle Group study.[69] Mr. Hevert agreed with Dr. Amit and explained that relative risk compared to other comparable companies is the significant point.[70]

The Commercial Group also 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.[71] The Commercial Group also recommended a reduction based on the Commission's practice of including CWIP in rate base. Both Dr. Amit and Mr. Hevert disagreed with the Commercial Group position regarding CWIP, noting that the Commission's long-standing policy regarding CWIP, which indicates that the market had already taken that position into account.[72]

8. Conclusion

To better and more reasonably address the effects of unsettled stock prices and the mandatory two-year effect of the ROE in this case, the Commission should take 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. With this in mind,

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68 Ex. 29, Hevert Surrebuttal at 2-7.

69 Ex. 403, Amit Surrebuttal at 28.

70 Ex. 28, Hevert Rebuttal at 49; Ex. 29, Hevert Surrebuttal at 7-8; Tr. Vol. 1 (Hevert) at 83, lines 13-15: "[E]stimating the cost of equity is by its very nature a comparative exercise, and it cannot be done in isolation, and you cannot look at such issues [risk reduction] on an absolute basis." Also Tr. Vol. 1 (Hevert) at 86 and 93-94

71 Ex. 225, Chriss Direct at 8-9.

72 Ex. 28, Hevert Rebuttal at 47-48; Ex. 402, Amit Rebuttal at 16.

the Company continues to recommend that the Commission adopt an ROE of 10.25 percent. If the Commission does not believe that the factors that affect the Company merit an increase in the ROE, the Company submits that the Commission certainly should not reduce the ROE below the currently authorized level of 9.83 percent.

B. Monticello LCM/EPU (Issue # 2)

1. Background

The Monticello LCM/EPU Program is a complex project undertaken to prepare Monticello for its 20-year extended operating life while increasing the plant's capacity from 600 to 671 MW.[73] The Company implemented the Program over approximately eight years, and replaced nearly all of the components that support the reactor and power generation equipment.[74] As discussed at some length in our last Minnesota rate case as well as this case, the Program is a unified and overlapping set of sub-projects that encountered challenges throughout its implementation.[75] Though not unusual in the evolving nuclear industry and for a plant of Monticello's type, these challenges increased overall Program costs well beyond our initial estimates and extended the time to complete the Program.

In the Company's prior rate case, the Commission concluded that the EPU portion of the Monticello 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 disallowed as a result "once the EPU is in service":

> 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 the Extended Power Uprate, which cannot serve ratepayers until it is licensed by the NRC. …

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[73] Ex. 51, O'Connor Direct at 15.
[74] Ex. 51, O'Connor Direct at 15.
[75] Ex. 51, O'Connor Direct at 16-17. *See also* Docket No. E002/GR-12-961 (Tr. Vol. 2 at 126 (O'Connor); Ex. 51, O'Connor Direct at 13; and Ex. 53, O'Connor Rebuttal at 4).

> 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, a 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.[76]

The Commission further deferred a review of the reasonableness of the underlying costs of the Program to the Prudence proceeding.[77]

A July 17, 2014 Joint Prehearing Order issued in this rate case and the Prudence proceeding requires that the prudence of total Program costs and the division of Program costs between the LCM and EPU are to be addressed in the Prudence proceeding.[78] The Order further notes that the issues to be decided within 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 rates; and (ii) how expenses from the Prudence proceeding should be recovered and amortized.[79]

With respect to the determination whether the EPU aspect of the Program should be considered in-service, the Company has agreed to the Minnesota Chamber of Commerce's proposal to defer recovery of depreciation and operating costs for the EPU portion of the Monticello Program until the plant achieves full ascension, and to amortize costs over the remaining life of the plant. The Company believes this resolution is in the public interest, because it recognizes the benefits our customers are receiving by having a fully uprate-licensed plant generating power during the test year, as well as addressing the ongoing financial loss the Company continues to

76 Order at p. 18, Docket E-002/GR-12-961.
77 Order at pp. 19-20, Docket E-002/GR-12-961.
78 Joint Prehearing Order at 2, Docket Nos. E-002/GR-13-868 and E-002/CI-13-754 (July 17, 2014).
79 Joint Prehearing Order at 2, Docket Nos. E-002/GR-13-868 and E-002/CI-13-754 (July 17, 2014).

experience because of the disconnect created between our financial accounting and regulatory accounting books. The Chamber's proposal further addresses any uncertainty that exists over whether the plant will achieve 71 MW in the test year.

We recognize the Chamber's proposal has not garnered consensus among all interested Parties. For that reason, and to the extent the ALJ and Commission do not adopt the Chamber's proposal, we believe the plant should be considered in service at the start of the test year consistent with the proposal we laid out in our direct case. Pertinent circumstances have changed since the Commission's decision in our last rate case; namely, the Company has received all licenses needed to operate at uprate levels and has operated at partial uprate levels during the test year. Thus the Company has met its burden to establish that the systems and assets installed through the Monticello Program are used and useful during the 2014 test year.

2. The Uprate at Monticello is Used and Useful

a. The Used and Useful Standard

The standard for utility property to be included in rates in Minnesota is set forth in Minn. Stat. § 216B.16, subd. 6. This statute requires that "the commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public."[80]

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."[81] Thus the "used and useful" standard is not a bright line test; rather, the determination of whether

[80] Minn. Stat. § 216B.16, subd. 6.
[81] *Senior Citizens Coalition v. Minnesota Public Utilities Commission,* 355 N.W.2d 295, 300 (Minn. 1984).

property is "useful" requires consideration of what is reasonable given the policy considerations and factual circumstances surrounding any given capital asset. "[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."[82] Put differently, "used and useful determinations are made on a case-by-case basis and are not established through the application of any set formula but rather in light of all the circumstances."[83] For purposes of this case, it is notable that the standard does not require property to be used to its full capacity or maximum benefit at all times in order to be considered used and useful.[84]

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."[85] *Connecticut Light & Power* illustrates this point. In that matter, the Connecticut Department of Public Utility Control (DPUC) was asked to determine whether three units of the Millstone nuclear facility, which had undergone a sustained outage for more than a year, should be considered "used and useful" before the units resumed service.[86] The DPUC focused

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[82] 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.").

[83] *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) (also available at http://159.247.49.194/ 85255F2C005B9480.nsf/0/DA73A3EF251AD86F8525657E0060C3B6?Open&Highlight=2,97-05-12) (last viewed on Sept. 17, 2014) (*Connecticut Light & Power Decision*) (citing *Pennsylvania Public Utility Comm'n v. Metro. Edison Co.*, 37 PUR4th 77, 86 (1979)).

[84] *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).

[85] 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).

[86] *Connecticut Light & Power Decision* at 1.

its decision on "whether the investment is or will be useful during the time period in which the rates are to be in effect," [87] and noted that:

> [T]the proper analysis does not center on the certainty with which the Company's restart estimate will be accurate, but instead examines the likelihood of restoration of service during the time period in which rates are to be in effect. Holding the Company's restart estimates to a standard of absolute certainty is inappropriate from both a practical and legal viewpoint.[88]

The Company believes that it is not necessary to apply a "restart" analysis to Monticello because the systems and assets implemented as part of the Monticello LCM/EPU program are already in use and serving customers. However, the DPUC's discussion is instructive if the Commission determines that whether the Monticello LCM/EPU Program assets are sufficiently "used and useful" to be included in rate base should turn on when the facility achieves full ascension. Because the uncontroverted evidence in this proceeding establishes that the Monticello facility is expected to ascend to its full capacity this year – and certainly within the time period in which rates are to be in effect – rate base treatment of all Monticello assets is appropriate.

b. Proposed Resolution of Program Cost Recovery

Despite this precedent, the Company acknowledges that our ascension to a full 71 MW has not yet been achieved, and that the ascension process has taken longer than we initially expected.[89] As a result, the Parties presented several alternative rate base treatment proposals in this case with respect to the Monticello LCM/EPU Program. We believe the Chamber's proposal presents the best balancing of interests, intergenerational equities, and recent Commission precedent.

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[87] *Connecticut Light & Power Decision* at 9.
[88] *Connecticut Light & Power Decision* at 18.
[89] Ex. 55, O'Connor Surrebuttal at 3-5.

The Chamber proposes to treat the delay in ascend fully to 671 MW similar to a mechanical failure, consistent with the Commission's 2013 decision regarding treatment of Sherco Unit 3.[90] 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.[91] This approach 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 Prudence proceedings.[92]

This approach to the Monticello LCM/EPU Program costs strikes a middle ground between placing the entire facility in service at the beginning of 2014 and the Department's harsher treatment which assumes the plant must fully ascend to 671 MW to be considered "used and useful." As the more moderate proposal, the Chamber's approach reasonably reflects the current status of Monticello and balances the interests of all stakeholders by recognizing that while the plant has not operated at full uprate capacity, a safer, more modernized nuclear power plant with all uprate licenses in place provides benefits to utility customers. The Chamber's more moderate approach also best reflects that the causes of delaying full ascension are not licensing or safety issues, but rather data issues the utility is in the process of reconciling for the benefit of all stakeholders.

The Chamber's proposal has the further benefit of treating the fuel clause and rate base issues in a reasonable manner by offering customers a reduction in rate base

[90] Ex. 341, Schedin Rebuttal at 8.
[91] Ex. 341, Schedin Rebuttal at 9.
[92] Tr. Vol. 3 at 141, 152-53 (Heuer); Ex. 90, Heuer Rebuttal at Schedule 17.

that would offset the cost of alternative replacement capacity.[93] 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.

Despite the Company's support for the Chamber's approach, as of the evidentiary hearings in this matter the Department has taken an "all or nothing" approach to the determination whether some EPU proportion of the integrated Monticello LCM/EPU Program is "used and useful." The Department's conclusion that the EPU megawatts should not be in rate base at all until the plant fully ascends to its maximum output would establish an inappropriate bright line test as to whether property is "used and useful," and would be inconsistent with any reasonable manner in which power plants run. Taken to its logical conclusion, the Department's "used and useful" standard could cause any plant to be removed from rate base during an outage, whether planned or unplanned and regardless of duration, simply because the plant was not operating at full capacity during that time. This cannot be the intent of the "used and useful" standard, as power plants necessarily do not operate at full capacity at all times, even when conditions are favorable and nothing more than routine maintenance is required. Perhaps for this reason, the "used and useful" standard does not require that utility assets are used to their maximum possible levels; rather, the standard is whether they are "reasonably necessary" for the benefit and service of customers. Because the Monticello Program assets and systems are fully in use and benefiting customers, the Company has met a reasonable "used and useful" standard.

In addition to applying the "used and useful" standard in a prejudicial manner, the Department's used and useful analysis depends on the assumption that there is an appropriate split between LCM and EPU activities such that one can designate certain assets or expenditures as not "used and useful" until the plant fully ascends.

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[93] Ex. 342, Schedin Surrebuttal at 4-5.

Although an LCM/EPU split was used in our prior rate case to recognize that the Company had not yet procured the license amendments necessary to operate at uprate conditions, but it is no longer relevant to a "used and useful" analysis. As Mr. O'Connor discussed in hearings and pre-filed testimony in some length,[94] the Company did not obtain NRC uprate licensing for certain assets or equipment, and cannot identify standalone systems that are operational solely upon receipt of the license. Rather, 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's treatment of LCM/EPU costs as one program even before full ascension is consistent with several regulatory cases in which common plant facilities are considered fully in-service even if a portion of the generation plant facilities they serve are not yet operational. For example, *State Ex Rel Utilities Commission v. Eddleman*, the North Carolina Supreme Court affirmed a North Carolina Utility Commission decision that Duke Power's interest in "common plant" serving two nuclear units was fully used and useful even when one of the two units was not yet operational.[95] In *Eddleman*, Duke Power's application for a rate increase included placement of the company's full ownership interest in "common plant"[96] associated with the Catawba Nuclear Station in rate base, along with the costs of the operational Unit 1. In contrast, Catawba Unit 2 was not yet operational and was not included in rate base.[97]

Because Catawba Unit 2 was not operational, the Commission's Public Staff contended that only half of the Catawba station's common plant should be associated with Unit 1 and included in Duke's rate base, with the other half classified as CWIP

[94] Tr. Vol. 1 at 220 (O'Connor); Ex. 53, O'Connor Rebuttal at 14.
[95] *State ex rel. Utilities Comm'n v. Eddleman*, 358 S.E.2d 339, 352 (N.C. 1987).
[96] *Eddleman*, 358 S.E.2d at 352 ("Switching stations, waste treatment facilities, shops, laboratories, roads and parking lots, all of which are intended to serve both generating units at Catawba, are examples of common plant. …").
[97] *Eddleman*, 358 S.E.2d at 352.

consistent with the Commission's treatment of Unit 2. The question, then, was whether the facility's "common plant" should be considered useful even though part of the facility was not yet operating (let alone operating at full capacity). The Commission and Supreme Court concluded the entire common plant should be considered "used and useful" and included in rate base because all common plant costs were necessary to serve the operational Unit 1:

> As we stated earlier, property of a public utility may be included in the utility's ratebase when it is used and useful in providing service to the public in this state. N.C. G.S. § 62-133(b)(1). The Commission properly recognized that this principle controlled its decision with respect to this matter, and found that all – not half – of Duke's interest in the common plant associated with Catawba Nuclear Station was, at the appropriate time, used and useful in providing service to North Carolina ratepayers. The question for this Court, then, is whether the Commission's conclusion is adequately supported by the evidence.
>
> <u>We think the evidence is sufficient to support the Commission's decision. Both Duke chairman Lee and William R. Stimart, a company vice-president, testified that all of the costs incurred for common plant are necessary for the safe and reliable operation of Catawba Unit 1. This testimony was uncontradicted.</u> The Public Staff's witness, James G. Hoard, acknowledged on cross-examination that he was unable to specify any common facilities that are not necessary for operation of Unit 1, and that he was simply proposing that half the cost of common plant be excluded from Duke's ratebase. In addition, appellant admits in its brief that Catawba's common plant "is indivisible, [and] in that sense . . . necessary for the safe, reliable operation of Catawba Unit 1.[98]

Likewise, *State ex rel. Missouri Public Service Co. v. Fraas,*[99] the Missouri court of appeals reversed the state commission's decision to only include 25 percent of new generation facility common costs in rate base because only one of four facility

[98] *Eddleman*, 358 S.E.2d at 352 (emphasis added).
[99] 627 W.W.2d 882 (Mo. App. 1982).

generation units had been completed in the test year.[100] The court concluded that all common facilities were used and useful in the test year because they were necessary to operation of the completed unit – and the same common plant would also support three additional units upon completion of those units and their placement in service.[101]

Similarly, all of the components of the LCM/EPU Program are in use serving the continuing operation of the plant, regardless of whether the plant operates at a full 671 MW. While there is debate in the current proceeding and the Prudence investigation regarding whether an LCM/EPU split should be utilized for determining the cost-effectiveness of the Program, no party has contradicted Mr. O'Connor's testimony that all Program equipment is operating to serve the Monticello plant prior to ascension. Consistent with the reasoning in *Edelmann*, the LCM/EPU Program assets and equipment are operating in a used and useful fashion. We believe the Chamber's proposal appropriately balances these factors with any concerns about the delays in full ascension.

The Department also implied at hearings that the Chamber's approach may require deferral approvals from the Commission that the Parties have not requested in this proceeding. We respectfully disagree with this characterization. The Chamber's proposal is similar to the Commission's treatment of costs in our 2013 rate case with respect to the extended Sherco 3 outage, where the Commission did not require a deferred accounting petition.[102] Rather, the Commission recognized that "the task at hand is to equitably balance the interests of the ratepayers and the shareholders"[103] and struck a balance between those interests based on the facts in that record.

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[100] 627 W.W.2d at 889.
[101] 627 W.W.2d at 889.
[102] Order at p. 23, Docket E-002/GR-12-961.
[103] Order at p. 22, Docket E-002/GR-12-961

For these reasons, we respectfully request that the Commission adopt the Chamber's proposal with respect to treatment of unrecovered Monticello LCM/EPU Program costs.

c. All Assets and Systems are Used and Useful

If the Commission does not adopt the Chamber's proposal, the Monticello LCM/EPU Program should be considered fully used and useful in 2014 for many of the same reasons identified above. The Recommendation and Commission Order in our 2013 rate case concluding that the EPU portion of the Monticello Program was not yet "used and useful" appeared to be premised on the facts that we did not yet have all licenses necessary to operate at uprate levels, and were not yet operating at uprate capacity.[104] Several key, undisputed factual differences exist between the circumstances of our 2013 test year and the current circumstances at Monticello. Taken together, these circumstances support that the EPU portion of the Program is used and useful for ratemaking purposes:

- *All License Amendments Received:* We have received all NRC licenses and amendments necessary to operate at uprate levels, including our EPU license amendment and MELLLA+ license.[105]
- *All Program Assets in Service:* We have begun 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.[106]
- *Partial Ascension Achieved:* We have achieved a partial uprate, ascending to 40 of the additional 71 MW additional capacity we expect from the Program.[107]

[104] Order at p. 18, Docket E-002/GR-12-961.
[105] Tr. Vol. 1 at 227 (O'Connor); Ex. 53, O'Connor Rebuttal at 4; Ex. 100, Clark Rebuttal at 23-24.
[106] Tr. Vol. 1 at 220 (O'Connor); Ex. 53, O'Connor Rebuttal at 14; Ex. 100, Clark Rebuttal at 24.
[107] Tr. Vol. 1 at 231 (O'Connor); Ex. 53, O'Connor Rebuttal at 10; Ex. 100, Clark Rebuttal at 24.

Importantly, "[f]rom an accounting viewpoint, the plant is not required to operate at 671 MW in order for the NRC license to be in service."[108]

- *Full Ascension Anticipated in 2014:* We anticipate achieving full ascension by the end of 2014, through the relatively normal process of validating post-licensing data for the NRC.[109]

For each of these reasons, the circumstances at Monticello are fundamentally different than those we faced in our 2013 rate case. Although all Program assets were in use and serving customers at that time, the ALJ and Commission found this insufficient to warrant rate base treatment because we did not have our license amendments[110] and we had not yet achieved any ascension. In the current proceeding, 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. As considered in conjunction with the "used and useful" standard, these facts illustrate that the assets are both in service and are providing increased capacity to customers in 2014 as well as facility safety and efficiency benefits. Further, the Program will continue to provide additional benefits as the ascension process progresses.

Finally, we believe it is important to highlight the policy considerations involved in this "used and useful" determination. The ALJ and Commission must make a decision, based on all the facts and circumstances, whether it is reasonable to include Monticello LCM/EPU costs in rates. Even applying a rigid used and useful standard, the Company has presented uncontroverted facts establishing that all the Company's investments are in use and serving customers in the form of uprate

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[108] Ex. 94, Perkett Rebuttal at 45.
[109] Tr. Vol. 1 at 231-233 (O'Connor); Ex. 55, O'Connor Surrebuttal at 5.
[110] Although the EPU license amendment was received in 2013 after evidentiary hearings concluded, our second license amendment for the fuel configuration (MELLLA+) was not received until March 2014 (per expectations). Tr. Vol. 1 at 227 (O'Connor).

capability, pending ascension, increased efficiencies, and a safer plant. We believe these are ample benefits to warrant considering the entire facility used and useful. As such, the record supports considering all Monticello Program costs used and useful" for purposes of our 2014 test year.

3. Conclusion

While the Company believes the Monticello LCM/EPU upgrades are used and useful and should be included in rate base, we recognize that there is some dispute on this point and that the plant has not yet ascended to full uprate capacity. The Chamber's proposal presents a reasonable approach to these competing considerations, and is consistent with the Commission's decision regarding our extended Sherco 3 outage. The Company therefore supports implementation of the Chamber's mechanism 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 proceeding.

C. Passage of Time (Issue #10)

The Passage of Time issue requires resolution of two questions: (1) is a passage of time adjustment appropriate if a utility, in this case the Company, requests recovery of less than its entire revenue deficiency in the second year of a MYRP, and (2) if the passage of time adjustment is appropriate, how should it be calculated and what is its value in this case? Regardless of how the Commission answers the first question, the answer to the second question moots this issue. The Company showed, and the Department did not disagree that a symmetrical "passage of time" adjustment that includes both impacts on rate base and depreciation expense should be considered [111] When both are considered, there is an increase to the cost of service. So regardless of ones' view of the appropriate multi-year plan structure, the adjustment is not supported.

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[111] Ex. 429, Campbell Direct at 158:4-5, 158:15-16, 158:19-20, 162:10, 162:18, 164:12-13; Ex. 435 Campbell Surrebuttal at 120:3-4; Tr. Vol. 4 at 53:10-20.

In response to the first question, the Company believes a passage of time adjustment in this case is neither appropriate nor reasonable. While the Company acknowledges that a passage of time adjustment may be appropriate in some limited instances – namely those in which the additions to rate base outpace the growth of the utility's depreciation expense – this is not the case here. As demonstrated on the record, the Company's depreciation expense in 2015 outpaces its additions to rate base.[112] Therefore, adjusting for the passage of time would increase the Company's 2015 Step request. The Company does not believe that this is consistent with the Commission MYRP and therefore did not make such a request

Further, should the Commission and ALJ adopt the passage of time adjustment in the instant context, it will send a signal which we believe will not advance the use of the multi-year rate plan, which is an innovative ratemaking tool. This is because utilities will be incentivized to (1) forego 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 the step years of a multi-year rate plan which may be inconsistent with the Commission's guidance, as provided in its MYRP Order.[113] For this reason, we believe a passage of time adjustment should not be made.

As it pertains to the second question, the Company believes, at a high-level, that the passage of time adjustment is calculated by reducing the accumulated depreciation reserve by depreciation expense. The Company notes that while there are technical differences between itself and the Department in how this general formula is applied, either application does not support the Department's downward adjustment of over $17 million. Rather the evidence on the record demonstrates that

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[112] Ex. 94, Perkett Rebuttal at pp. 4-7.

[113] *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").

the application of a passage of time adjustment in this case would result in an increase to the 2015 Step revenue requirements by at least $950,000.[114]

1. Background

The instant case is the first Multi Year Rate Plan (MYRP) filed in the state of Minnesota.[115] The Commission provided guidance for MYRPs in its 2013 MYRP Order,[116] which, in part, requires that MYRPs be "designed to recover the costs of specific, clearly identified capital projects and, as appropriate, non-capital costs."[117] Consistent with the Commission MYRP Order, the Company's "multi-year rate plan seeks to recover costs related to specific capital projects and a limited number of non-capital expenses associated with capital investments."[118] 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.[119]

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, <u>except</u> such calculations were limited to only the 2015 Step capital additions and related O&M. This includes carrying forward "ongoing monthly balances … for various components of rate base including plant in-service, Construction Work In Progress (CWIP), accumulated depreciation provision, and accumulated deferred

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114 Ex. 94, Perkett Rebuttal at Schedule 2, page 5 (subtracting the 2015 total change in accumulated depreciation from the 2015 total change in depreciation expense).
115 Ex. 99, Clark Direct at 9:23-24.
116 *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").
117 *Id.* at p. 5.
118 Ex. 99, Clark Direct at 10:16-18.
119 Ex. 95, Robinson Direct at 3:17-22.

taxes."[120] The 2015 Step revenue requirements therefore reflect the incremental revenue requirement for these costs between 2015 and 2014.[121]

During discovery, the Department issued information request No. 2113 which sought to quantify a passage of time adjustment by requesting the following information:

> Please 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).[122]

The Company responded to this request by inadvertently responding with only the amount associated related to the depreciation reserve roll forward amount requested (rate base) and not the associated depreciation expense, and arrived at an amount of $17,529,000.[123]

Although the Company's 2015 Step request was limited to certain capital projects and their related O&M costs as required by the MYRP Order, the Department proposed an additional adjustment updating both the depreciation reserve <u>and</u> expense, as well as an adjustment for retirements, for the <u>entirety</u> of the Company's rate base to account for the "passage of time" during the years of the MYRP.[124] The Department has proposed an adjustment of approximately $17.5 million to account for this passage of time and approximately $500,000 accounting for plant retirements in 2014.[125]

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[120] Ex. 95, Robinson Direct at 5:15-17.
[121] Ex. 95, Robinson Direct at 7:15-22.
[122] Ex. 430, Campbell Direct at Schedule NAC-32.
[123] *Id.*
[124] Ex. 429, Campbell Direct at 158:4-6.
[125] Ex. 429, Campbell Direct at 164:11.

2. Passage of Time Adjustment Discourages MYRPs

By limiting the out years of an MYRP to specific capital projects and their related O&M, the Commission has indicated that it wants the results of an MYRP to rates that do not fully reflect all changes to a utility's cost of service for each year of the MYRP. While this does not allow a utility to recover its entire cost of service for each year of a multi-year rate plan, as shown by the Company's instant rate case, this construct has merit when there are appropriate capital projects justifying the use of an MYRP.

The Department's passage of time adjustment seeks to adjust a significant portion of the overall out year cost of service: that portion related to depreciation for each year of the MYRP. By doing so the Department does not factor in that only specific capital additions, and related O&M, appear to be allowed in year two and three rates. We believe adjusting one particular component of a utility's cost of service automatically due to the passage of time, while the utility is not (or even may not) adjusting the other components of its second or third year cost of service (for example, wage increases) reduces the efficacy of a multi-year construct.

Specifically, the passage of time adjustment sends a signal to a utility to file back-to-back rate cases to the extent it recognizes a need to adjust rates beyond the initial test year of a traditional rate case. This is because consecutive rate cases allow a utility to propose a rate adjustment for the entirety of their cost of service without having to worry about a passage of time adjustment. Thus, the passage of time adjustment appears to funnel utilities away from multi-year rate plans and to traditional rate cases.

Furthermore, a passage of time adjustment effectively penalizes a utility for not requesting to recover its entire cost of service. As the logic behind the adjustment goes, there is no need for a passage of time adjustment when a utility requests its entire cost of service in the second and/or third year of a multi-year rate plan. Since the MYRP Order appears to suggest that a utility cannot request its entire cost of service in step years, adopting a passage of time adjustment as part of this case will mean that the Company, as well as other utilities, could be subject to this adjustment in future multi-year rate cases. By limiting a utility's step requests to capital projects and related O&M, and including a passage of time adjustment, a utility will be less able to address its revenue deficiency needs and as a result not earn its authorized return. This possibility reduces the incentive for a utility to utilize this innovative ratemaking tool.

We believe an outcome of this nature would be inconsistent with the legislative intent of the statute authorizing multi-year rate plans and the MYRP Order.

3. Growth of Depreciation Expense Does Not Justify a Passage of Time Adjustment

The Company limited its 2015 Step request consistent with the Commission's guidance in its MYRP Order.[126] Specifically, the company is requesting to recover $98.5 million of the approximately $117.9 million forecasted 2015 deficiency.[127] The $98.5 million[128] represents: the selected annualization of several 2014 capital additions; selected 2015 capital additions; and O&M costs related to these capital projects.[129] In other words, the Company, as part of the MYRP, has requested to include in rates approximately eighty-four percent of its 2015 forecasted revenue deficiency (i.e., the amount it would be permitted had it chosen to file a traditional rate case in 2015).

Looking only at capital additions, the total 2014 to 2015 "overall growth in rate based for plant, accumulated depreciation, and related deferred taxes is $713.4 million for the Total Company – Minnesota, North Dakota and South Dakota (Total

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126 MYRP Order at p. 5.

127 Ex. 25, Sparby Direct at 4:23. The Company notes that appropriate information to audit the complete 2015 revenue deficiency was included in Ex 88, Heuer Direct at Schedule 26. No party has challenged this information.

128 Ex. 25, Sparby Direct at 3:18.

129 Ex. 95, Robinson Direct at 3:6-29:5.

Company) [while] the proposed 2015 Step rate base for the 36 projects is $579.9 million (Total Company)."[130] In other words, the Company is requesting to include in rates only approximately eighty-two percent of its total year-on-year growth in rate base.

The Company's calculation of the 2015 Step revenue requirement also carries forward both the changes to depreciation reserve and depreciation expense as relates to the capital projects included in the 2015 Step.[131] No party has contested the appropriateness of doing so, nor the calculation itself. This is also consistent with how such calculations would be performed had the 2015 Step projects been included in a rider, as the rider would only calculate revenue requirements for a particular capital addition included in the rider.

While no party contests our compliance with the Commission's MYRP Order, the Department proposes to roll forward the accumulated depreciation reserve and depreciation expense "from non-Step projects placed in service in 2014."[132] The Department justifies this proposal by stating it would be "inequitable to allow the Company to add $68.85 million in plant additions for 36 capital projects … without reflecting the reduced depreciation expense and related accumulated depreciation for existing plant in rate base …."[133]

However, as discussed further below, the Department makes no allowance for the fact that our depreciation expense in 2015 is growingly more rapidly than our additions to rate base such that, even if a passage of time adjust were appropriate under the Commission's MYRP, it would increase our rates in 2015, not decrease them. On this basis alone the proposed adjustment should be rejected.

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130 Ex. 429, Perkett Rebuttal at 4:10-15.
131 Ex. 435, Campbell Surrebuttal at 111:18-19 (confirming that the "Company recorded all revenue requirements components (including depreciation) for the 36 capital projects included in their 2015 Step").
132 Ex. 94, Perkett Rebuttal at 5:2-4.
133 Ex. 429, Campbell Direct at 158:13-17.

Notwithstanding this, the Department reasoned that an "update for the passage of time for 2015 depreciation for plant in rate base is symmetrical to the Company's update of the 2015 step depreciation update for their 36 capital projects."[134]

The Company respectfully disagrees. For the Department's proposed passage of time adjustment to be symmetrical, the sets of capital additions affected must match. They do not under the Department's methodology, because the Department's proposal is to roll forward depreciation reserve and expense for the entirety of the Company's 2014 rate base as an offset to the Company's limited 2015 Step request.[135] We do not believe this to be symmetrical.

For the passage of time adjustment to be symmetrical, 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 be made needs to include the full revenue requirement impacts of the plant that is being annualized."[136] This would result in a $1.9 million increase to the Company's 2015 Step revenue requirement.[137] The Company has not sought to include this additional $1.9 million in rates.

Similarly, with respect to plant retirements, the Department is also seeking an unbalanced adjustment. Fundamentally, the record establishes that the scope of the second year of a multi-year plan [is not] similar to a full test year where we would factor in all changes in the historical asset base year over year."[138] However, by removing retired plant in 2014 from rate base in 2015, the Department is essentially updating the second year of the MYRP with downward adjustments to rate base

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[134] Ex. 429, Campbell Direct at 162:22-24.
[135] Ex. 429, Campbell Direct at 162:13-16 ("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") (emphasis added).
[136] Ex. 94, Perkett Rebuttal at 5:2-9.
[137] Ex. 94, Perkett Rebuttal at 5:10.
[138] Ex. 94, Perkett Rebuttal at 6:17-19; MYRP Order at p. 5 ("the Commission will consider multiyear rate plans that are designed to recover the cost of specific, clearly identified capital projects …").

without the Company having requested (or having the opportunity to request under the Commission's MYRP Order) its entire cost of service in 2015.

4. Correct Calculation of Passage of Time Adjustment

As demonstrated above, the Department's proposed passage of time adjustment is asymmetrical and should be rejected. However, in the event that the ALJ chooses to adopt the Department's proposal, the $17.5 million calculation of the adjustment is not consistent with the Department's proposal to carry forward both the depreciation reserve and expense on the entirety of the Company's 2014 rate base.[139] The $17,528,919 million downward adjustment reflects only the rolling forward of the depreciation reserve[140] and not the concomitant $18,478,528 increase in depreciation expense.[141] Netting these two items together would result in the correct passage of time upward adjustment of $949,609.

The Department is clear that its proposed passage of time adjustment is intended to capture the change from 2014 to 2015 of <u>both</u> accumulated depreciation reserve <u>and</u> depreciation expense.[142] The Company recognizes that the Department's calculation of the approximately $17.5 million passage of time adjustment is based on the Company's response to a particular information request.[143] However upon examination, it is clear that the response to that information request was incomplete and only contained a response that discussed the change in depreciation reserve from 2014 to 2015 and did <u>not</u> contain the offsetting amount of change in depreciation expense from 2014 to 2015. Consequently, the $17.5 million calculation of the passage of time adjustment is incomplete.

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139 *See* Ex. 429, Campbell Direct at Schedule 31 (calculating only depreciation reserve roll forward from 2014 to 2015).
140 *Id.*
141 *See* Ex. 94, Perkett Rebuttal at Schedule 2, page 5 (calculating both the roll forward of depreciation reserve and expenses).
142 Ex. 429, Campbell Direct at 158:4-5, 158:15-16, 158:19-20, 162:10, 162:18, 164:12-13; Ex. 435 Campbell Surrebuttal at 120:3-4; Tr. Vol. 4 at 53:10-20.
143 *See* Ex. 429 Campbell Direct at Schedule 32.

The Company did inform the record with the complete components of the passage of time adjustment which includes <u>both</u> the approximately $17.5 million change in depreciation reserve, along with an approximately $18.5 change in depreciation expense.[144] Consequently, the record contains all the information necessary to calculate the true passage of time adjustment through the netting of these two amounts.[145] This results in an approximate $950,000 upward adjustment.

5. Conclusion

We do not believe this issue should ever have arisen. While we take some fault in providing an incomplete answer, we remedied this with additional information in rebuttal. This adjustment is both lopsided and unsupported and should be rejected.

D. Pension and FAS 106 Expense – 2008 Market Loss (Issues # 5, 6)

1. Background

Like other utilities, the Company offers its employees not only current cash compensation, but also retirement benefits, including a defined benefit qualified pension plan and a medical benefit for eligible retired employees.[146] 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.[147] The Company also eliminated the post-retirement medical benefit for current employees more than a decade ago.[148] 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.[149]

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144 Ex. 94, Perkett Rebuttal at Schedule 2, page 5.
145 Tr. Vol. 5 at 53:21-54:17 (Campbell).
146 Ex. 82, Moeller Direct at 11-12.
147 Ex. 82, Moeller Direct at 101.
148 Ex. 82, Moeller Direct at 68 (stating that the Company "eliminated its post-retirement medical benefit for active employees in 1998 and 1999 as its first step in reducing overall retirement benefits"); *id.* at 114 ("The current expense for retiree medical benefits is a legacy of the prior programs.").
149 Ex. 78, Figoli Direct at 24 (showing that Xcel Energy's retirement benefits rank 39 out of 42 companies for both bargaining and non-bargaining employees when compared to peer companies).

Over the last five years, the Company's qualified pension expense has increased when compared to levels a decade ago. This is primarily because of two factors related to the deep economic recession that began in 2008. The first is the inclusion in qualified pension expense of a phased-in and amortized portion of the asset losses attributable to the large drop in the equities market in 2008 (2008 Market Loss).[150] The second factor is a lower discount rate created in large part by the Federal Reserve's efforts to stimulate the national economy in the wake of the 2008 market downturn.[151]

The question facing the Commission is whether the Company should be allowed to include those after-effects of the 2008 market crash in the calculation of qualified pension expense and retiree medical expense. For the following three reasons, the Commission should allow the after-effects to be included in the calculation.

- For decades the Company has followed the same formula, which incorporated the gains and losses from prior years, to calculate its current-year pension and benefits expense. The Company did not change its method of calculating qualified pension expense after the 2008 Market Loss. The test year pension expense is no different and is a product of applying the same formula.
- Customers have benefited greatly from the consistent application of these methods. Prior to 2008, there were many years where our pension expense was nominal in comparison to the benefits paid to our eligible employees. In fact, the unrebutted evidence established that customers have saved more than $330 million in qualified pension expense since 2000 on a Minnesota

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150 Company witness Mr. Mark Moeller explains what is meant by the terms "phased in" and "amortized" in the context of the Company's qualified pension expense. Ex. 82, Moeller Direct at 18-32.
151 Ex. 82, Moeller Direct at 31 ("Those discount rate reductions were caused largely by the Federal Reserve's infusion of low-cost capital into the economy.").

jurisdictional basis because of the Company's consistent inclusion of prior-period gains and losses in the calculation of qualified pension expense.

- The Company calculated its test year qualified pension expense and retiree medical expense in accordance with the applicable standards, including Generally Accepted Accounting Principles (GAAP). No party has provided a valid reason to deviate from those standards in this case.

While the Department contests the Company's proposed qualified pension expense and retiree medical expense, the record is uncontested as to the foregoing facts. Indeed, the Department does not contend the Company's calculation of qualified pension expense or retiree medical expense is erroneous in *any* respect. Rather the Department believes a downward adjustment is reasonable because it will make our expenses more "fair". The Company does not believe the Department's approach is consistent with fundamental rate making principles. The Company has met its burden of proof to establish the correct amounts of both qualified pension expense and retiree medical expense and as a result the Commission should approve recovery of the 2008 Market Loss.

2. Long-Standing Practice

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.[152] The issue to be resolved is whether it is "reasonable" to include amounts attributable to prior-period gains and losses, including the 2008 Market Loss, when calculating the retirement benefits reflected in the Company's revenue requirement.

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[152] Ex. 82, Moeller Direct at 56 ("Retirement benefits are a legitimate cost of service, and it is reasonable to recover from customers either the costs of our qualified pension or a reasonable alternative to it."); Ex. 429, Campbell Direct at 99 ("Overall, I note that the Department does not object to paying reasonable salaries and benefits to utility employees; such reasonable costs are necessary in the provision of utility service.").

The Company has incorporated the gains and losses from prior years in calculating its current-year pension and benefits expense for decades. In fact, the use of prior-period gains and losses is necessary to arrive at an accurate measure of current-period pension expense.

The Company has two qualified pension plans – the NSPM Plan and the XES Plan.[153] The calculation of pension expense for the NSPM plan is governed by the Aggregate Cost Method (ACM), whereas qualified pension expense for the XES Plan is calculated in accordance with Statement of Financial Accounting Standard (FAS) 87.[154] Although the methods prescribed by the ACM and FAS 87 for calculating pension expense differ,[155] both methods rely on the Company's experience from prior years to determine the current pension expense.

a. ACM Calculation

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).[156] Each year, the Company and its actuaries determine how much the plan assets are worth, and then they determine the present value of the benefits that the plan will be responsible for providing to beneficiaries in the future. The difference between those amounts is the unfunded liability that must be funded over the future working lives of current employees.[157] If the value of the assets exceeds the PVFB, the amount that must be funded is zero. If the PVFB exceeds the value of the assets, the shortfall must be funded.

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153 Employees of NSPM are eligible to participate in the NSPM Plan, and employees of Xcel Energy's service company subsidiary, Xcel Energy Services Inc., are eligible to participate in the XES Plan. Ex. 82, Moeller Direct at 15.

154 Ex. 82, Moeller Direct at 15-16.

155 The methods are described in detail in Mr. Moeller's direct testimony. *See* Ex. 82, Moeller Direct at 14-43.

156 Ex. 82, Moeller Direct at 32-33.

157 Mr. Moeller's testimony contains a numerical example of how this calculation works. *See* Ex. 82, Moeller Direct at 33.

In determining the asset value, the Company incorporates the prior-period gains or losses,[158] but the entire asset gain or loss from prior years is not included in the pension plan's asset value all at once. Asset gains and losses are phased into qualified pension expense over a five-year period, and then they are amortized over a certain number of years.[159] 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 total $95.5 million for the NSPM Plan, only $6.2 million is being included in the test year qualified pension expense as a result of not only the phase-in and amortization, but also of the offsets from other prior-period gains.[160]

Two things are apparent from the foregoing description of the qualified pension expense calculation under the ACM. First, the Company has not "attempt[ed] to get recovery of *all* of the 2008 market loss from ratepayers in the short term."[161] Rather the test year qualified pension expense reflects the consistent application of the ACM pension expense calculation.

Second, including the phased-in and amortized portion of the 2008 Market Loss (*i.e.*, the $6.2 million) in the market value of the asset does not represent a deviation from the normal method of calculating the asset value used to establish

158 The meaning of "gains" and "losses" in this context is not self-evident. As explained in Mr. Moeller's testimony, the elements used to calculate pension expense are established at the beginning of each year based on actuarial studies. Ex. 82, Moeller Direct at 17. At the end of the year, the assumptions are trued up to actual experience, and the differences give rise to gains or losses. *Id.* Thus, "[a]sset gains or losses arise when the actual returns on the pension trust assets in prior years are greater than or lesser than the expected return on those assets." *Id.* at 19.
159 Ex. 82, Moeller Direct at 26-27. As explained by Mr. Moeller, the term "amortization" is something of a misnomer insofar as the ACM is concerned because the Company recalculates the amount each year and sets the expense to recover the newly calculated amount. *Id.*
160 Ex. 82, Moeller Direct at 29-30 ("[A]s I noted earlier, the 2014 pension expense is affected not only by the 2008 Market Loss, but also by the Company's experience in 2009 through 2012. Because the NSPM Plan experienced gains in 2009, 2010, and 2012, the net amount of prior period asset losses to be amortized in 2014 is $6.2 million, not $8.6 million." (cell references omitted)); *see also id.*, Schedule 5 at 1, cell G44.
161 Ex. 435, Campbell Surrebuttal at 91 (emphasis in original).

qualified pension expense under the ACM.[162] To the contrary, the NSPM Plan asset value is nothing more than the sum of prior contributions, prior-period gains, and prior-period losses.[163]

Indeed, Ms. Campbell conceded that the 2008 Market Loss reduced the value of the Company's pension plan assets, and that the reduced value of the assets gives rise to increased pension expense: "If the value (balance) of the Pension Plan Assets decreases, the amount that the Company needs to recover over time increases."[164] It is not clear why the Department seeks to exclude part of the 2008 Market Loss after conceding that it is reasonable for the market value of the pension plan assets to be lower in the wake of a market loss.

b. FAS 87 Calculation

The method for calculating qualified pension expense under FAS 87 differs 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."[165] To achieve that goal, FAS 87 requires the utility to measure pension expense based on five individual components: service cost, interest cost, EROA, prior service cost, and the net gain or loss from prior years.[166]

For purposes of this proceeding, the important element is the net asset gain or loss from prior years, which occurs because the EROA in a prior year was different from the actual return in that year.[167] Similar to the calculation of asset values under

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162 Ex. 83, Schrubbe Rebuttal at 18 (stating that the "2008 Market Loss is not included as a separate adjustment in the calculation of pension expense. Instead, the effect of the 2008 Market Loss is that it altered the balance between pension assets and liabilities by significantly swinging the balance toward liabilities.").
163 Ex. 83, Schrubbe Rebuttal at 16 (stating that the Company "is seeking to include all prior performance since the beginning of the Plan, which happens to include 2008 performance, in determining pension expense for the 2014 test year").
164 Ex. 429, Campbell Direct at 128.
165 Ex. 83, Schrubbe Rebuttal at 17.
166 Ex. 82, Moeller Direct at 36.
167 Ex. 83, Schrubbe Rebuttal at 21. The gains or losses from prior years can also be liability gain or losses, but those are not implicated by the 2008 Market Loss, which deals only with asset losses.

the ACM, the net gain or loss under FAS 87 includes the netting of many pre-2008 gains, the 2008 Market Loss, and post-2008 gains and losses.[168] That net number is then combined with the other four elements of pension expense under FAS 87 to determine the test year qualified pension expense.

The salient points for purposes of FAS 87 are essentially the same as those for the ACM. First, the Company is not seeking to recover "all of the 2008 market loss from ratepayers in the short term." Of the $36.1 million of unamortized XES Plan losses remaining from the 2008 Market Loss, the Company is seeking to recover only $3.46 million in the test year qualified pension expense.[169]

Second, including the phased-in and amortized portion of the 2008 Market Loss for the XES Plan is not a departure from the usual way of calculating qualified pension expense. To the contrary, incorporating a portion of the 2008 Market Loss is no different from incorporating the pre-2008 market gains or the post-2008 net gains or losses. There is no reason to treat the 2008 Market Loss differently when calculating the qualified pension expense for the XES Plan.

3. Customer Benefits over Time

Including prior-period gains and losses in the calculation of qualified pension expense is not only appropriate but also beneficial because the prior-period gains reduced or even eliminated pension expense from the Company's cost of service in most years. In fact, for the period from 2000 through 2014, the Company's customers saved approximately $332 million on a Minnesota jurisdictional basis because of the use of prior-period experience in the calculation of pension expense.[170]

Those savings manifest themselves in annual pension expense that is lower than it otherwise would have been. For example, from 2006 through 2010 the Company's customers paid approximately $1 million in annual pension expense, even

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168 Ex. 83, Schrubbe Rebuttal at 21.
169 Ex. 82, Moeller Direct at 30.
170 Ex. 82, Moeller Direct at 60.

though the Company's true pension costs were roughly $26 million per year in those years.[171] Thus, customers have benefited from real and significant savings in recent years as a result of the inclusion of prior-period gains in the calculation of current pension expense.

As noted earlier, in 2008 the Company's pension trusts suffered deep losses as a result of the worst economic downturn since the Great Depression. But 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.[172] 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.[173]

Our qualified pension expense calculations were previously accepted when prior-period experience reduced qualified pension expense. It was only when customers were asked to pay current pension expense that reflected prior-period losses that the inclusion of prior-period experience in the calculation of qualified pension expense was challenged. And even now, the Department believes customers should benefit from the prior-period gains that have accrued since 2008.[174] There cannot be one rule for prior-period gains and another rule for prior-period losses. Having accepted the benefits of the prior-period gains for many years, it cannot now be argued that customers should be shielded from any responsibility for prior-period losses.

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171 Ex. 82, Moeller Direct at 8.
172 Ex. 82, Moeller Direct at 6.
173 Ex. 82, Moeller Direct at 61 (noting that the cumulative impact of the 2009-2012 asset returns on the Minnesota jurisdiction 2014 test year has been a reduction of $2.4 million for the NSPM Plan and a reduction to expense of approximately $34,000 for the XES Plan).
174 Aug. 15 Tr. at 64 (Ms. Campbell testifying, "The gain is already captured in the total pension expense. And I'm not really taking issue with the gain, except for maybe indirectly by saying I thought the gain should be bigger because of financial conditions of the market being higher than the 2008 levels.").

4. No Valid Reason to Exclude a Portion of the 2008 Market Loss

In direct testimony, Ms. Campbell offered two reasons for her recommendation that the Commission exclude half of the 2008 Market Loss from the calculation of qualified pension expense. First, she stated that the Company had made "an extra adjustment to current rates for the 2008 market loss."[175] Second, she stated that, even though the Company calculates the majority of its qualified pension expense using the ACM, the Company appeared to be using FAS 87 to justify its "extra adjustment."[176]

In rebuttal testimony, Company witness Mr. Richard Schrubbe demonstrated mathematically that the Company had not made an extra adjustment for the 2008 Market Loss, but instead had calculated the qualified pension expense in exactly the way the Department thought it should have been calculated.[177] The Company also demonstrated that it had not calculated all of the qualified pension expense using FAS 87. It had calculated the qualified pension expense for the NSPM Plan using the ACM, and it had calculated the qualified pension expense for the XES Plan in accordance with FAS 87.[178]

On surrebuttal, Ms. Campbell conceded her two prior arguments,[179] and advanced several new arguments to support her recommended disallowance of half the phased-in and amortized portion of the 2008 Market Loss from qualified pension expense.[180]

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175 Ex. 429, Campbell Dir. at 129.
176 Ex. 429, Campbell Dir. at 129-30.
177 Ex. 83, Schrubbe Rebuttal at 19-22.
178 Ex. 83, Schrubbe Rebuttal at 23.
179 Ex. 435, Campbell Surrebuttal at 92 ("On pages 17-24, Mr. Schrubbe provide[s] additional information to show the 2008 market loss is embedded in the pension expense calculation and, based on my limited review, I believe that to be true.").
180 The Company notes these arguments were raised for the first time in surrebuttal even though each one related to the Company's direct case. For example, Ms. Campbell asserted for the first time on surrebuttal that the Company's retirement benefits may be too generous. Ex. 435, Campbell Surrebuttal at 90-91. But the Company described the retirement benefits it offers in its direct testimony, not its rebuttal testimony. Ex. 82, Moeller Direct at 11-12. Indeed, Ms. Campbell herself listed the retirement benefits on pages 104-107 of

The Company believes the Department's surrebuttal arguments do not support any downward adjustment of its qualified and retirement benefit expenses. Although Ms. Campbell asserted in surrebuttal that she finds it "troubling" that the Company is seeking recovery in rates of both the defined benefit plan costs and the 401(k) match,[181] she offered no evidence that the Company's request to recover both amounts is unreasonable. In contrast, the evidence on the record demonstrates that the Company's "retirement program for new hires ranks as one of the lowest among peer companies" and that "our legacy retirement program would benchmark slightly lower than our peer companies median retirement programs."[182] The Company also offered evidence that the 5 percent Cash Balance program, which is the defined benefit retirement program available to newly hired employees, provides only an 8 percent income replacement level.[183] Therefore, the existence of a 401(k) benefit in addition to a qualified pension benefit does not support a 50 percent downward adjustment.

The Department also expressed concern that the Company "may not have reasonably managed their pension plan" because the Company has not fully recovered the losses attributable to the 2008 Market Loss.[184] However, there is no evidence of unreasonable or imprudent management of the pension assets. Instead, the evidence on the record demonstrates that the Company holds a diversified portfolio because it must balance the opportunity for financial market growth with its obligations to

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her direct testimony, but nowhere in that testimony did she urge the Commission to disallow half of the 2008 Market Loss on the ground that the Company's overall retirement benefits are too generous.

181 Ex. 435, Campbell Surrebuttal at 91.

182 Ex. 78, Figoli Direct at 24-25.

183 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.").

184 Ex. 435, Campbell Surrebuttal at 94. In her direct testimony, Ms. Campbell states that the Company might have failed to manage its pension trust assets properly, but she did not assert that as a ground to disallow part of the 2008 Market Loss. She mentioned it only in connection with her argument that December 31, 2013 might not be an appropriate measurement date for calculating qualified pension expense. Ex. 429, Campbell Direct at 123.

maintain minimum funding levels, its obligation to pay monthly cash benefits to retirees, and its fiduciary duty to the pension trust funds' beneficiaries.[185]

Additionally, each asset class in the pension trust performed consistent with market returns in 2013, as evidenced by the 33.3 percent return on U.S. equities.[186] Thus, the only evidence in the record on the management of the pension trust funds establishes that the Company managed its assets prudently.

In closing, the Company notes there is no evidence to support a disallowance of "half" the phased-in and amortized portion of the 2008 Market Loss. The recommended disallowance percentage is arbitrary, as evidenced by the fact that the Department put forward the same percentage disallowance on direct and surrebuttal, even though its reasons for the recommended disallowance were altogether different.

5. No Support for FAS 106 Disallowance

The Department is also recommending that half of the phased-in and amortized portion of the 2008 Market Loss calculated under FAS 106 be excluded from the calculation of retiree medical expense. But Department witness Ms. Angela Byrne did not offer any independent reasons for that proposed exclusion. Instead, she relied on the reasons offered by Ms. Campbell for excluding half of the 2008 Market Loss from the qualified pension expense calculation.[187] Because Ms. Campbell's proposal disallowance of the 2008 Market Loss is not supported, the Commission should also not accept Ms. Byrne's proposed exclusion of the 2008 Market Loss.

6. Conclusion

Prior-period gains and losses are an integral part of the calculation of qualified pension expense under both the ACM and FAS 87, and there is no advanced reason which suggests that this should not continue, more specifically, to exclude any of the

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185 Aug. 11 Tr. at 106.
186 Aug. 11 Tr. at 106.
187 *See* Aug. 15 Tr. at 13.

phased-in and amortized portions of the 2008 Market Loss. Accordingly, the Company requests that the Commission grant its request to recover its qualified pension expense in the test year, including the 2008 Market Loss. Similarly, the evidence on the record supports the Company's request to recover its FAS 106 expense in the test year, including the 2008 Market Loss

E. Pension and FAS 106 Expense – Discount Rate (Issues # 4, 6)

1. Background

The Company calculates qualified pension expense under the NSPM Plan by comparing the asset value to the PVFB, the latter of which is the present value of future benefits that the plan owes to its beneficiaries. Similarly, for purpose of determining qualified pension expense under FAS 87, the Company must calculate its future liabilities, which are reflected in the service cost and interest cost. Finally, the Company calculates its future retiree medical liabilities under FAS 106.

To discount those liabilities payable in future years to present value, it is necessary to have a discount rate. For historical reasons, the Company uses the EROA to discount liabilities to present value for the NSPM Plan.[188] But for the XES Plan qualified pension expense and FAS 106 retiree medical expense, the Company uses a discount rate set in accordance with a bond-matching study. Such a study includes a matching bond for each of the individual projected payout durations within the plan based on projected actuarial experience.[189] The bonds used in the study must meet certain well-established criteria,[190] and the Company employs numerous tests to validate the reasonableness of the discount rate produced by the bond-matching study.[191]

For the period ending December 31, 2012, the bond-matching study produced a discount rate of 4.03% for the XES Plan and 4.08% for retiree medical expense. In

188 Ex. 82, Moeller Direct at 86.
189 Ex. 82, Moeller Direct at 82.
190 Ex. 82, Moeller Direct at 82 (describing the criteria).
191 Ex. 82, Moeller Direct at 82-84.

response to discovery in this case, the Company provided its updated discount rate as of December 31, 2013, which was 4.74 percent for the XES Plan and 4.82 percent for retiree medical expense.[192] The Company and Department have agreed that year-end 2013 discount rates should be used to calculate liabilities for the XES Plan and the retiree medical expense.[193]

The Department contends that the discount rates used to calculate qualified pension expense for the XES Plan and to calculate retiree medical expense should have been even higher. According to Ms. Campbell, the discount rate for the XES Plan should have been equal to the EROA used for the XES Plan, which was 7.25%.[194] Ms. Byrne contends that the discount rate for calculating retiree medical expense should have been 7.11%.[195] The evidence on the record, however, does not support deviating from GAAP, or establishing a different discount rate/EROA construct for regulatory accounting purposes. Therefore, we respectfully request the ALJ and Commission approve the use of the 4.74 percent discount rate for FAS 87, and the 4.82 percent discount rate for FAS 106.

2. Company's Proposed Discount Rate is Reasonable

The Commission should adopt the discount rate proposed by the Company for several reasons. First, 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% for 151 Towers Watson clients in the Fortune 1000, and the Citigroup benchmark on that date was 4.95%.[196] As these figures show, the discount rate used by the Company in this case is far closer to the industry norm than

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192 Ex. 83, Schrubbe Rebuttal at 39.
193 Ex. 83, Schrubbe Rebuttal at 39.
194 Ex. 429, Campbell Direct at 118.
195 Ex. 423, Byrne Direct at 42.
196 Ex. 83, Schrubbe Rebuttal at 44.

the 7.25% discount rate proposed by the Department. This means the discount rate proposed by the Company is representative of market rates.

Second, 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.[197] Most recently in May 2014, NSPM issued $300 million of 30-year first mortgage bonds at a rate of 4.125%, and customers will benefit from that favorable cost of debt over the entire lives of the bonds.[198] 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.[199]

Third, it is inappropriate to change the method for calculating FAS 87 pension expense at this late date. 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 and interest cost elements of the FAS 87 calculation would have been higher.[200] But customers did not pay those higher service cost and interest cost amounts in prior rates, and it is inappropriate to assume they did.

3. No Reason to Increase the Discount Rate

The Department argues that the discount rate for the FAS 87 calculation should equal the EROA. The Company respectfully disagrees. First, the discount rate used by the Company is not "artificially low."[201] As noted earlier, the discount

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197 Ex. 83, Schrubbe Direct at 45 (stating that "customers have benefited enormously from those low interest rates in the form of reduced borrowing costs").

198 Ex. 83, Schrubbe Rebuttal at 45; *see also* Ex. 82, Moeller Direct at 10 (stating that "lower interest rates have also reduced our cost of service by reducing our debt costs").

199 Ex. 83, Schrubbe Rebuttal at 45; Ex. 82, Moeller Direct at 11 ("The Commission should avoid taking the benefits of a low interest rate environment in one portion of our cost of service while adjusting for offsetting impacts of it in another.").

200 Ex. 82, Moeller Direct at 89 (stating that if the EROA had been used as the discount rate for ratemaking purposes in prior years the pension expense in those years "would presumably have been higher because the discount rate is also used to calculate the interest components of the FAS 87 pension expense").

201 Ex. 429, Campbell Direct at 116.

rates used to calculate the Company's FAS 87 qualified pension expense are consistent with the rates used to set the Company's debt rates for new issuances of debt and market values. Moreover, current bond-yield rates are not a temporary aberration. Rates commensurate with current levels have been in effect for more than half a decade now.[202]

In contrast, the Department is proposing a discount rate for FAS 87 which is not representative of current rates. In fact, the Department's recommended discount rate is higher than any ten-year treasury rate in the last decade.[203]

Second, the Company is not manipulating pension expense by using the EROA "to inflate . . . the value of pension plan assets to future years when the retirees will retire," while using a "point in time" measurement to calculate pension liabilities.[204] The EROA is an offset to the service cost and the interest cost components of the FAS 87 calculation.[205] Thus, the Company's use of an EROA higher than the discount rate actually reduces pension expense, rather than inflates it. Moreover, Ms. Campbell's statement that the discount rate represents a "point in time" measurement proves too much. *Every* measurement of financial values is a point-in-time evaluation, including the EROA.

Finally, departures from GAAP when establishing pension expense for ratemaking purposes should be the exception and not the norm. Unless there is a good reason to depart from GAAP, the Commission should adhere to it to avoid creating a disparity between regulatory books and accounting books. Typically, alternatives to GAAP are considered when the GAAP-reported results are volatile or

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202 Ex. 83, Schrubbe Rebuttal at 45 ("[D]iscount rates were considerably higher in prior years. To the extent they appear 'artificially low' now, it is only because the Federal Reserve has kept interest rates low to stimulate the economy in the wake of the deep recession of 2008-2009."); *id.* at 41 ("As discussed by Company witness George Tyson, the FAS 87 discount rate is representative of interest rates over the last five years and our expectations for interest rates this year.").
203 Ex. 31, Tyson Rebuttal at Schedule 1, p. 3.
204 Ex. 429, Campbell Direct at 116-117.
205 Ex. 82, Moeller Direct at 37 ("The EROA is an offset to the service costs and interest costs, and therefore it reduces the amount of pension expense.").

when the Commission has approved an alternative accounting method under FAS 71, neither of which is present here.[206] Discount rates have stabilized since the market loss in 2008 and forward projections are also stable.[207]

4. No Reason to Increase the FAS 106 Discount Rate

The Department recommends that the discount rate used to calculate retiree medical expense also be increased to match the EROA, which is 7.11% for FAS 106 purposes. But similar to the recommendation on the 2008 Market Loss, Ms. Byrne did not offer any independent reasons for increasing the FAS 106 discount rate. Instead, she relied entirely on the reasons offered by Ms. Campbell for increasing the FAS 87 discount rate.[208] Because Ms. Campbell's proposal to increase the discount rate is inappropriate for the reasons set forth above, the Commission should also reject Ms. Byrne's proposed increase to the FAS 106 discount rate.

5. Conclusion

The discount rates proposed by the Company for calculating FAS 87 qualified pension expense and FAS 106 retiree medical expense are based on objective, verifiable data from bond-matching studies and are consistent with discount rates used by the majority of the utilities in the United States. Moreover, the Company has consistently used those discount rates to calculate pension expense and retiree medical expense in the past, and changing them now would inappropriately shift risk to the Company. Finally, none of the reasons offered by the Department justify the increase in discount rates and the resulting disallowances. Accordingly, the Commission should approve the Company's proposed discount rates for calculating FAS 87 and FAS 106 expenses.

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206 Ex. 83, Schrubbe Rebuttal at 41.
207 Ex. 83, Schrubbe Rebuttal at 41.
208 *See* Aug. 15 Tr. at 13.

F. Total Labor Adjustment (Issue # 7)

1. Test Year Total Labor Costs Are Reasonable

Just like prior rate cases, the Company is including total labor costs in the cost of service. To support its test year labor costs, the Company's provided, in its initial filing, total labor costs by both object account[209] and FERC account[210] for review and audit by interested parties. Additionally, each Company core operations witness provided a discussion of their O&M budgets, including labor costs, and the cost trends and drivers of these budgets.[211] No party challenged the reasonableness, prudence, or necessity of the Company incurring these costs, on an individual basis.

The Department initially proposed an adjustment to the Company's test year to address a claimed historic over recovery of paid leave costs.[212] 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.[213] Thus, on an overall basis, the Company's total labor costs were representative of its cost of service.

Upon this showing, the Department withdrew its proposed paid leave adjustment;[214] 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 an unsupported statement that total labor increases must be capped at three percent.[215]

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209 Ex. 17, Initial Filing, Vol. 6, Schedule 3.
210 *Id.* at Schedule 4.
211 Ex. 51, O'Connor Direct at 81:1-118:24; Ex. 62, Harkness Direct at 56:21-83:23; Ex. 58, Mills Direct at 7:20-40:8; Ex. 65, Kline Direct at 9:9-27:12; Ex. 69, Foss Direct at 6:7-27-5.
212 Ex. 429, Campbell Direct at 95:1-98:22.
213 Ex. 87, Stitt Rebuttal at 3:7-9:3.
214 Ex. 435 Campbell Surrebuttal at 74:5-8; Tr., Vol. 5, at 33:3-8 (Campbell).
215 Ex. 435, Campbell Surrebuttal at 72:21-74;2

The Company respectfully disagrees with this proposed adjustment and continues to believe the evidence on the record demonstrates the reasonableness of its test year labor costs.

The Company has established 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.[216] The Company has met its burden to demonstrate that the increases in Nuclear and Business Systems labor costs are prudently incurred[217] and no party has questioned this fact.[218]

With respect to labor costs, Company witness Mr. Timothy J. O'Connor justified the need for our labor costs within the Nuclear Business Area:

> 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.[219]

Mr. O'Connor then goes on to support the need for these increased labor costs in significant detail.[220] With the exception of the nuclear retention program (which is a resolved issue between the Company and the Department),[221] no party has challenged the necessity, prudence, or reasonableness of these costs. Consequently, the Company has met its burden of proof.

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216 Ex. 129, Stitt Opening Statement at p. 2; Tr. Vol. 2 at 38:12 – 39:17 (Stitt).
217 *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. 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").
218 Tr. Vol. 2 at 40:1-25 (showing no cross examination of Ms. Stitt by any party).
219 Ex. 51, O'Conner Direct at 83:1-6.
220 Ex. 51, O'Conner Direct at 83:8-90:26.
221 If the ALJ were to accept the Department's total labor adjustment, it would double count the resolved adjustment for nuclear retention.

With respect to Business Systems labor costs, Company witness Mr. David C. Harkness has identified the need for our labor spend within the Business Systems Business Area, identifying increases in headcount in the Business Systems area[222] and an increase in contract labor for a variety of support needs.[223] Mr. Harkness also provides considerable support and justification for these increases.[224] No party has questioned the necessity, prudence, or reasonableness of these costs. Consequently, the Company has met its burden of proof.

"When 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."[225]

2. Total Labor Adjustment Will Not Result in Representative Costs

The Company further disagrees with the Department's proposed adjustment because it will not result in the Company recovering its representative labor costs.

The Commission's rules define a "test year" as the 12-month period selected by the utility for the purpose of expressing its need for a change in rates.[226] "The test year concept is designed to produce a measure of a regulated utility's earnings for a known period of time, to enable the regulatory body to make an accurate prediction of revenues and expenses in the reasonably near future."[227] Consistent with this 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.

222 Ex. 62, Harkness Direct at 76:11-16.
223 Ex. 62, Harkness Direct at 78:15-20.
224 Ex. 62 Harkness Direct at 76:9-80:1.
225 Ex. 129, Stitt Opening Statement at p. 2.
226 Minn. R. 7825.3100, subp. 17.
227 *Northwestern Bell Telephone Co. v. State*, 253 N.W.2d 815, 822 (Minn. 1977).

The record demonstrates that the Company's total labor costs can fluctuate significantly from year to year. The Department's own analysis indicates that that the Company's total labor costs increased three percent from 2011 to 2012, then increased approximately twelve percent from 2012 to 2013 and are expected to decrease approximately four percent from 2013 to 2014.[228] Based on this, there is no discernable trend in the Company's total labor costs but, rather, different activities in a particular year drive certain increases or decreases in these costs.[229] Therefore, the total labor costs in this test year should be judged on the merits of the forecasted cost of service during the test year.[230] Historical comparisons should be rejected due to these fluctuations.

Rather than reviewing the reasonableness and representativeness of the test year total labor costs, the Department observes that "2013 actual labor costs were abnormally high due to nuclear plant outages and the usually [*sic*] high number of storms."[231] The Department then removes these events to normalize its 2013 labor costs to the three percent increase experienced by the Company from 2011 to 2012. The Department then carried forward this three percent increase to the test year and proposed an adjustment to bring the Company's representative test year total labor costs down to that level.[232] The only support for this adjustment is the Department's witness' statement that "an increase of 2 to 3 percent over the costs of a normal year is generally a reasonable increase for labor."[233]

The Department's analysis therefore rejects establishing a representative cost in the test year. The Company demonstrated that there are legitimate reasons that its

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228 Ex. 435, Campbell Surrebuttal at 72:10-11.
229 Ex. 87, Stitt Rebuttal at 6:10-7:18 (discussing the drivers of the different total labor costs for the different years presented).
230 *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).
231 Ex. 435, Campbell Surrebuttal at 72:19-20.
232 Ex. 435, Campbell Surrebuttal at 73:13-74:1-3.
233 Ex. 435, Campbell Surrebuttal at 72:21-73:1.

total labor costs have fluctuated from year to year based on the work it undertook to provide electric service to its customers. It is not reasonable to use these prior labor costs to craft a normalized recovery cap. The Company has demonstrated its forecasted needs during the test year and its projected total labor costs to meet these needs. The labor budgets for each of the Company's business units (with the exception of items resolved between the Company and Department) have not been challenged. As a result, the Department's proposed total labor adjustment should be rejected.

III. OTHER DISPUTED REVENUE REQUIREMENT ISSUES

A. Prairie Island EPU (Issue # 3)

1. Background

The Company respectfully requests recovery of our prudently-incurred costs spent to initiate our now-cancelled extended power uprate (EPU project, or the Project) at the Prairie Island Nuclear Generating Plant (Prairie Island). The Prairie Island EPU was planned as a 164 MW increase in capacity between our two Prairie Island nuclear generation units.[234] The Project was the subject of an extensive Certificate of Need proceeding that began in May 2008, and was initiated upon receiving the Certificate of Need in December 2009.[235] Our costs incurred prior to Project cancellation were primarily incurred in late 2009 through 2011 for the purpose of assembling the comprehensive EPU license amendment request (LAR) package to the Nuclear Regulatory Commission (NRC).[236] Due to changing circumstances that evolved throughout 2011 (and which are described in more detail below), the Company initiated a Changed Circumstances proceeding in the first quarter of 2012 to reassess the Project. These proceedings culminated in the Commission's February 27,

[234] Ex. 49, McCall Direct at 10.
[235] Ex. 48, Alders Direct at 8-9.
[236] Ex. 45, Weatherby Direct at 23-24.

2013 Order Terminating the Certificate of Need Prospectively, which was issued the day before responsive Direct testimony deadlines in our 2012 rate case.[237]

The remainder of our 2012 rate case included discussion and testimony as to whether Project cost recovery should have been sought in the course of that rate proceeding.[238] Ultimately, the Commission's final Order in our 2012 rate case 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."[239]

The Company's initial filing in this proceeding included the required complete justification of rate recovery, including Prairie Island EPU Direct and Rebuttal policy testimony by Company witness Mr. Christopher Clark;[240] Project technical and project management Direct Testimony by Mr. Scott McCall;[241] resource planning and regulatory Direct Testimony by Mr. James Alders,[242] and Project accounting and cost tracking testimony by Mr. Scott Weatherby.[243] The Company proposed to recover total Project costs of $66.1 million plus accrued AFUDC of $12.8 million over 12 years with a return on the regulatory asset, or to amortize cost recovery over 6 years with no return on the asset.[244] These amortization proposals would allow the Company to recover its prudently-incurred costs while reducing the immediate impact of the investment on customers.

In responsive testimony, no Party suggested that the Company had not provided the complete justification required by the Commission's 2012 rate case order, and no party challenged the underlying vendor and internal costs giving rise to

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237 Prairie Island EPU Certificate of Need, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY at 4, Docket No. E002/CN-08-509 (Feb. 27, 2013).
238 ALJ's Report at pp. 86-91, Docket No. E002/GR-12-961 (July 3, 2013).
239 Order at Order Point 51, Docket No. E002/GR-12-961 (Sept. 3, 2013).
240 Ex. 99, Clark Direct; Ex. 100, Clark Rebuttal, and Ex. 20, Errata.
241 Ex. 49, McCall Direct.
242 Ex. 48, Alders Direct.
243 Ex. 45, Weatherby Direct; Ex. 47, Weatherby Rebuttal.
244 Ex. 99, Clark Direct at 31.

the total Prairie Island EPU costs. However, several Parties (the Department, Chamber, 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.[245] In Surrebuttal Testimony and at hearing, the Company and the Department each testified that recovery of Project costs over the remaining life of the facility with a debt-only return of 2.42 percent would be acceptable.

Separately, the OAG suggested that the Company should be precluded from recovering $10.1 million in Project costs, any return on the Project costs, and any AFUDC for the Project 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 Project costs by cancelling the Project earlier or providing the Commission with earlier updates about evolving circumstances that affected the Project.[246] Finally, 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." With the exception of the OAG's position on AFUDC recovery, which is addressed in the "CWIP/AFUDC" segment of this brief, we address each of these issues in turn.

2. Cost Recovery Standard

The Commission has addressed several cancelled and abandoned projects in recent years, and established a clear standard for recovery of cancelled project costs. In particular, the Commission "has consistently treated the issue of abandoned plant costs as turning on the unique facts and circumstances surrounding each rate case and each plant."[247] Thus the standard for a cancelled project is not, as the ICI Group

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[245] Ex. 437, Lusti Direct at 12-18; Ex. 340, Schedin Direct at 10-11; Ex. 250, Glahn Direct at 10-12.
[246] Ex. 370, Lindell Direct at 35-44.
[247] *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, E001/GR-10-276, FINDINGS OF FACT CONCLUSIONS AND ORDER, (Aug. 12, 2011) [*hereinafter* E001/GR-10-276 ORDER] .

suggests, whether it becomes "used and useful" under the typical plant-in-service test. If a "used and useful" test were applied, by definition no project that was cancelled before it was placed in service could be eligible for cost recovery.[248] Rather, the appropriate test is whether the costs were "prudently incurred in good-faith":

> 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.[249]

3. Reasonableness of Prairie Island EPU Costs

Although no Party challenges the specific internal and vendor costs incurred to carry out the Prairie Island EPU, in light of the cost recovery standard noted above we underscore the reasonableness of these costs to inform a determination of the appropriate amortization and recovery of Project costs.

As Mr. Alders discussed in testimony in detail, the Prairie Island EPU project was proposed to meet our customers' growing energy needs forecasted over the course of several resource plans and carried through our Prairie Island EPU Certificate of Need.[250] The Company undertook Project activities in good faith based on this need and the projected benefits of the Project.[251]

However, the circumstances in which we were working the Project began to change and reduced the long-term benefits of the Project over the course of 2011 and 2012. Company witness Mr. McCall detailed the circumstances that unfolded, including: a moderate reduction in Project scope in early 2011; the disaster at

[248] Ex. 99, Clark Direct at 34.
[249] E001/GR-10-276 ORDER.
[250] 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*, MPUC Docket No. E002/CN-08-509, INITIAL FILING (May 16, 2008).
[251] Ex. 49, McCall Direct at 40.

Fukushima Daichii in March 2011, with the impacts developing throughout 2011; the delay in receiving an extension of the Prairie Island operating license from late 2010/early 2011 to June 2011, which delayed the timeframe in which we could file a LAR package with the NRC; our experience with the 2011 Monticello LCM/EPU outage, which raised concerns that construction issues like we experienced at Monticello might arise at Prairie Island; the addition of new, costly, and time-consuming NRC requirements for LAR package submission and new information about a likely delay in the NRC's review of the initial LAR package (from 12-24 months to 30-36 months); softening of customer demand throughout 2011; and increases in natural gas prices as 2011 progressed.[252]

In light of these considerations, we re-evaluated the likely benefits of the Prairie Island EPU and could not conclusively determine whether the risks of continuing the Program outweighed the benefits.[253] We therefore began minimizing costs and suspending the Project in the late third quarter of 2011, notified the Commission that the Project required further discussion among stakeholders,[254] and incurred no avoidable project costs after December 2011.[255]

The Company filed a Notice of Changed Circumstances in March of 2012.[256] In later 2012, we identified that substantial outage cost savings could be captured by redirecting EPU assets – namely, new fuels at the plant – to prolong the time between

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252 Ex. 49, McCall Direct at 23-32; Ex. 48, Alders Direct at 11, 13-17.
253 Ex. 48, Alders Direct at 18.
254 Ex. 48, Alders Direct at 16-17.
255 Ex. 49, McCall Direct at 33-34, 38 ("'Had the Company recommended cancellation at the time of its first changed circumstances filing, would it have avoided any other costs?' 'No. Other than the work Westinghouse completed in order to develop a substantially complete LAR package, our work had ceased.'"). In addition, Mr. McCall discusses the industry-standard milestone structure of the Westinghouse contract, making it more prudent by late 2011 to allow Westinghouse to continue the LAR contract than to cancel it, make cancellation payments, and receive no further deliverables. *Id.* at 34-36; Tr. Vol. 1 at 201-202 (McCall).
256 *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*, MPUC Docket No. E002/CN-08-509, NOTICE OF CHANGED CIRCUMSTANCES AND PETITION (Mar. 30, 2012).

outages rather than to complete an uprate.[257] We therefore filed an October 2012 supplement to our Notice of Changed Circumstances supporting project cancellation,[258] after which the Commission voted in favor of cancellation in December 2012 and issued a February 2013 Order Terminating the Prairie Island EPU Prospectively.[259]

4. Amortization of Cancelled Project Costs

In surrebuttal, the Department indicated that amortization of 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.[260] During the evidentiary hearing, and although this return percentage is lower than the Company calculated, we accepted the Department's proposal in the interest of resolving this issue and for the further benefit of our customers.[261] The Company believes this resolution to be in the public interest since it allows the Company to recover the majority of its costs for a project endeavored in good faith while acknowledging that our customers are not getting the same benefits that could have been realized had the project been placed into service.

Should our resolution of this issue with the Department not be accepted, the Company maintains that recovery of the full Prairie Island EPU costs over 12 years with a return on the asset would be appropriate. No party has suggested that the Company pursued the Prairie Island EPU imprudently, and apart from the OAG no Party has suggested the Company did not promptly and appropriately bringing the

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257 Ex. 49, McCall Direct at 36; Ex. 48, Alders Direct at 19-20.
258 *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*, MPUC Docket No. E002/CN-08-509, SUPPLEMENTAL FILING (OCT. 22, 2012).
259 Prairie Island EPU Certificate of Need, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY at 4, Docket No. E002/CN-08-509 (Feb. 27, 2013).
260 Ex. 442, Lusti Surrebuttal at 6-7.
261 Tr. Vol. 2 at 112 (Clark).

changed circumstances to the Commission's attention. Rather, the Parties have taken various policy positions regarding amortization of Project costs over 10 years with no return (OAG) or over the remaining 20-year life of the facility with no or a low return (ICI if recovery permitted, Department, Chamber).

Our initial proposals to recover Project costs over 12 years with a return on the asset, or over 6 years with no return, are also consistent with Commission precedent. Amortization over 12 years is a longer amortization schedule than the Commission approved in 2006 for costs associated with our cancelled Private Fuel Storage project,[262] and longer than the amortization period for the costs of the cancelled portion of Otter Tail Power's Big Stone II project.[263] While the Commission did amortize the costs of Interstate Power & Lights' cancelled Sutherland Generation Station Unit 4 (SGS4) project over a longer period, SGS4 was not the subject of a Minnesota Certificate of Need and was not supported by the same Minnesota process that led to development of the Prairie Island EPU.[264]

5. Full Cost Recovery is Appropriate

The OAG makes several arguments regarding the Company's management of the Project cancellation process, and suggests that recovery of Project costs should be reduced to account for these considerations.

First, the OAG contends that cost recovery is barred in this rate proceeding because the Company sought neither cost recovery nor deferred accounting in our 2012-2013 rate proceeding. Whether the Company was required to seek cost recovery in the 2012 rate proceeding was addressed in that docket, and resulted in the Commission's conclusion that the Company should provide a complete justification

262 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, Docket No. E-002/GR-05-1428 (Sept. 1, 2006).

263 *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).

264 *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 33 (Aug. 12, 2011).

of cost recovery or deferred accounting in the current rate case.[265] The Company did so, and the OAG has not argued that the Company's justification was incomplete or that the Company has not established the elements of deferred accounting. As a result, the only questions for this proceeding are the reasonableness of the underlying costs and the manner of recovery. Those issues are addressed above.

Second, OAG witness Mr. Lindell suggests the Company could have brought a Notice of Changed Circumstances earlier and thereby avoided certain Project costs. This contention implies that there was some clear, earlier time when the Company should have known it was necessary to suspend and cancel the Project. However, this position is not consistent with the fluid circumstances we experienced throughout 2011 or the fact that there was never a point in 2011 or early 2012 when cancelling the Project was clearly appropriate. Rather, we continued to identify net PVRR benefits for the Project in our March 2012 Changed Circumstances filing,[266] and the Department and other parties independently concluded at that time that the Project should proceed.[267] In addition, the OAG does not specify what costs could have been avoided by bringing a Changed Circumstances filing earlier, and does not acknowledge that the Company had both effectively suspended the Project by the end of 2011 and provided extensive changed circumstance information in our December 2011 update to our 2010 Resource Plan.[268] Given that it was not clear even in late 2012 that the Project should be cancelled,[269] the timing of the Company's Changed Circumstances filing and project suspension had virtually no impact on Project costs.

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265 Order at 54, Docket No. E002/GR-12-961 (Sept. 3, 2013).
266 Ex. 48, Alders Direct at 16, 18.
267 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*, Docket No. E002/CN-08-509, COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE – DIVISION OF ENERGY RESOURCES (JUNE 12, 2012).
268 Ex. 48, Alders at 16.
269 Ex. 48, Alders at 20-21.

Third, the OAG argues 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. However, the OAG misapprehends the applicable standard. 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. The creation of a regulatory asset does not govern future rate recovery decisions, but rather recognizes that rate recovery has yet not been resolved.[270]

Here, the Company accounted for the accumulated Prairie Island EPU costs at the end of 2012 in a manner consistent with GAAP and FERC accounting rules, after consultation with our with independent external auditors.[271] The Company reassessed the situation at the end of 2013 and again concluded rate recovery would be decided in a future year.[272] In each instance, the Company's external auditors did not take exception to either the Company's GAAP-basis or FERC-basis financial statements.[273] As a result, and 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 should not affect Project cost recovery in this proceeding.

Finally, the OAG argues the Company should be required to permanently write off $10.1 million of Project costs because the Company recorded a regulatory asset at the end of 2012 (when we needed to close our books for financial accounting purposes) and took a $10.1 million pretax charge to reflect uncertainty whether the Company would earn a return on the Prairie Island EPU asset. In other words, the OAG suggests the Company cannot recover these dollars for ratemaking purposes because it already "wrote them off" for financial accounting purposes.

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270 Tr. Vol. 1 at 181 (Weatherby).
271 Tr. Vol. 1 at 181 (Weatherby).
272 Tr. Vol. 1 at 181 (Weatherby).
273 Tr. Vol. 1 at 181 (Weatherby); Ex. 47, Weatherby Rebuttal at 4.

This position again misconstrues the nature of a regulatory asset. The pretax charge does not represent a "write off" of actual Project costs; rather, under GAAP it accounted for cost recovery over at least 12 years without earning a return.[274] Put differently, 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."[275] If a $10.1 million portion of total Prairie Island EPU costs were disallowed and the Company does not earn a return on the asset, the Company would take a $10.1 million impairment charge in addition to the $10.1 million pretax charge.[276] This result is inconsistent with the Company's prudent Project management and reasonable Project costs.

6. Conclusion

The Company believes that amortizing Prairie Island EPU costs over the remaining life of the Plant with a 2.24 percent debt return appropriately balances stakeholder interests without chilling utilities' willingness to propose cancellation of a project. The Company believes the OAG's and ICI's harsh 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.

B. CWIP and AFUDC (Issue # 63)

1. Background

In the Company's 2012 rate case, the OAG raised certain issues related to the Company's accounting for Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (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

[274] Ex. 47, Weatherby Rebuttal at 6; Tr. Vol. 1 at 182 (Weatherby).
[275] Tr. Vol. 1 at 182 (Weatherby).
[276] Tr. Vol. 1 at 182 (Weatherby).

of CWIP in rate base and the calculation of AFUDC."[277] The Commercial Group similarly contested the Company's accounting for CWIP.[278] After reviewing the arguments of the Parties, the ALJ made the following findings:

> 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.
>
> **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 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.[279]

Upon review of these recommendations, the Commission concluded that it would permit inclusion of CWIP and AFUDC in that case but require "a more detailed explanation of the Company's CWIP and AFUDC practices in its next rate case."[280] 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

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277 Docket No. E002/GR-12-961, ALJ FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at p. 129 (July 3, 2013).
278 Docket No. E002/GR-12-961, ALJ FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at p. 129 (July 3, 2013).
279 Docket No. E002/GR-12-961, ALJ FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at p. 130 (July 3, 2013).
280 Order at 10, Docket No. E002/GR-12-961.

> also address whether a minimum dollar level should be set for projects in CWIP.[281]

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.[282] Specifically, Ms. Perkett explained that the Company's inclusion of CWIP in rate base is subject to a revenue requirement of AFUDC incurred in the year, which effectively eliminates the cost of financing construction from the revenue requirement during the construction period.[283] The utility is then allowed to include AFUDC in the final cost of the asset at the end of construction.[284] As a result, these costs are deferred and amortized over the life of the asset after being placed in service.

In responsive Direct Testimony, the OAG and CG witness Mr. Criss made many of the same arguments the ALJ considered and rejected in Docket No. E002/GR-12-961. More specifically, in this case the OAG recommended:

- 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;
- AFUDC should only be allowed on capital projects costing more than $25 million;

281 Order at 54, Docket No. E002/GR-12-961.
282 Ex. 92, Perkett Direct at 51-63; Ex. 91, Guest Direct (throughout).
283 Ex. 92, Perkett Direct at 53.
284 Ex. 92, Perkett Direct at 54.

- 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
- AFUDC should be disallowed for the Prairie Island EPU project for 2011 and 2012.[285]

CG witness Mr. Chriss also recommended excluding CWIP from rate base, but did not address the reduction in net income resulting from the AFUDC offset. As noted in Ms. Perkett's Rebuttal Testimony, the Company assumes Mr. Chriss is proposing the elimination of both CWIP and the AFUDC offset such that the Company's response to Mr. Lindell also responds to Mr. Chriss.[286]

The evidence on the record demonstrates that the Company has met its burden of proof that its CWIP/AFUDC accounting is consistent with FERC requirements and should not be modified in any way.

2. The Company's CWIP/AFUDC Accounting is Consistent with FERC Requirements

With respect to AFUDC and CWIP in this proceeding, the Commission's first requirement is for the Company to "provide evidence of FERC's accounting requirements for CWIP/AFUDC and demonstrate that it has met the FERC requirements."[287] In detailed Direct Testimony, the Company explained its treatment of AFUDC and CWIP as consistent with FERC accounting standards. Ms. Perkett

[285] 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.
[286] Ex. 94, Perkett Rebuttal at 15. Mr. Chriss did not provide subsequent pre-filed or hearing testimony, so the Company continues to believe the noted assumption is correct.
[287] Order at 54, Docket No. E002/GR-12-961.

noted that 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:

> CWIP is included in rate base as authorized by Minn. Stat. § 216B.16, subd. 6. Depending on the nature of the project, CWIP is offset by AFUDC as authorized by Minn. Stat. § 216B.16, subd. 6a.[288] The AFUDC calculation is based on a formula prescribed by FERC in the Uniform System of Accounts, Plant Instructions Section 3 components of Construction Costs, (17) Allowance for Funds Used During Construction. The rate used is based on a two-step calculation, where short-term debt is used first and, upon exhaustion of the short-term debt amounts, a weighted blend of long-term debt and common equity is applied.[289]

Ms. Perkett further explained that 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.[290] 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.[291]

This accounting method is somewhat different than FERC's typical approach but is consistent with FERC requirements. 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

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[288] Subdivision 6a provides in relevant part: "To the extent that construction work in progress is included in the rate base, the commission shall determine in its discretion whether and to what extent the income used in determining the actual return on the public utility property shall include an allowance for funds used during construction."

[289] Ex. 92, Perkett Direct at 54-55.

[290] Ex. 92, Perkett Direct at 56.

[291] Ex. 92, Perkett Direct at 56.

rate making. The Minnesota treatment of AFUDC in ratemaking is in line with the USofA.[292] 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.[293] When FERC wishes to provide an incentive to investment in certain types of projects, it provides a current return on those projects by placing those projects in CWIP without an AFUDC offset.[294] For projects not earning a current return, the only difference in revenues between the FERC method and the Minnesota method is in the timing of the cash flow, as both methods provide for full recovery of financing costs during construction.[295] Like the FERC method, the Minnesota method allows the Company to recover its full financing costs.

In taking issue with the Company's approach, Mr. Lindell appears to conflate the Company's treatment of CWIP and an AFUDC offset with the opportunity to include CWIP in rate base with a current return. Mr. Lindell references a page from the Federal Register dated May 27, 2011, and concludes that it "explains the mutually exclusive ratemaking alternatives to either (1) include CWIP in rate base and stop accruing AFUDC; or (2) exclude CWIP from rate base and continue to accrue AFUDC."[296] The referenced footnote actually states that the mutually exclusive ratemaking methodologies are to "accrue carrying charges on CWIP in the form of AFUDC or earn a return on CWIP included in rate base."[297] Thus the issue is not whether CWIP can be included in rate base at all, but whether CWIP in rate base should earn a current return or should be subject to an AFUDC offset and accrual.

As Ms. Perkett noted in her Direct Testimony, the Company typically employs the latter approach, and only earns a current return without an AFUDC offset for (1)

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292 Ex. 94, Perkett Rebuttal at 19.
293 Ex. 94, Perkett Rebuttal at 17-18, 25.
294 Ex. 94, Perkett Rebuttal at 17-18.
295 Ex. 94, Perkett Rebuttal at 18, 24.
296 Ex. 320, Lindell Direct at 20; Ex. 321, Lindell Direct Schedules at Schedule JJL-5.
297 Ex. 321, Lindell Direct Schedules at Schedule JJL-5 (76 Fed. Reg. 103 at 30875, n.43 (May 27, 2011)).

transmission and renewable energy projects, for which earning a return on CWIP without an AFUDC offset both serves as an incentive and supports the Company's need to finance these very large projects; and (2) for projects costing less than $25,000 and completed in less than 30 days.[298] The latter projects are quickly placed into service and are providing service to customers at the time general rates are in effect; therefore, there is no reason for an AFUDC offset.[299] For all other projects, the Company includes an AFUDC offset.

Finally, the OAG suggests that the Commission should not permit the Company to include CWIP in rate base because "neither MERC, nor CenterPoint, in their most recent rate cases, included CWIP or AFUDC to set rates."[300] As the ALJ noted in our prior rate case, "[t]he OAG's reliance on the MERC decision is not well taken. In the MERC docket, the decision to exclude CWIP arose from the inclusion of CWIP late in the rate-setting process. In this matter, there has been ample time for discovery and a full inquiry into the Company's CWIP projects."[301] In addition, MERC's late request to include CWIP sought a current return on CWIP with no AFUDC offset,[302] which is different from the circumstances the Company presents. While it is not clear why CenterPoint Energy elected not to include CWIP in rate base – and therefore has not included an AFUDC offset – it is our understanding that CenterPoint's forecasted test year assumed that most of the CWIP was in-service and in rate base.[303] In addition, CenterPoint Energy's reliance on short-term debt varied greatly from year to year and was zero in 2012.[304] Thus, the AFUDC offset would

[298] Ex. 92, Perkett Direct at 56-57.
[299] Ex. 94, Perkett Rebuttal at 28-29.
[300] Ex. 320, Lindell Direct at 23.
[301] Docket No. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION at p. 129.
[302] 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, 011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 33-34 (July 13, 2012).
[303] Ex. 94, Perkett Rebuttal at 26-27.
[304] Ex. 94, Perkett Rebuttal at 26-27.

virtually eliminate the effect of including CWIP in rate base. Both of these situations are distinguishable from the Company's practices consistent with its own circumstances, FERC precedent, and Commission requirements.

As previously noted, 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.[305] However, 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.[306] Thus the 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.

3. The OAG Approach Improperly Calculates AFUDC Rates

As part of the discussion of the Company's compliance with FERC requirements for CWIP and AFUDC accounting, the Company provided testimony explaining its proper calculation of the AFUDC rate.[307] Mr. Lindell agreed both in testimony and at hearing that "NSP's formulaic calculation of AFUDC is compliant with FERC requirements."[308] Thus the question with respect to the Company's calculation of AFUDC rates is not whether FERC rules warrant a different calculation, but whether the Commission should adopt Mr. Lindell's alternate proposal that incorporates only the simple average of short and long-term debt rather than the Company's total cost of capital. Because the OAG's proposal would calculate AFUDC rates in a manner that is inconsistent with the Uniform System of Accounts and with the manner in which the Company uses capital to fund

305 Ex. 94, Perkett Rebuttal at 25.
306 Ex. 94, Perkett Rebuttal at 25.
307 Ex. 92, Perkett Direct; Ex. 91, Guest Direct.
308 Tr. Vol. 3 at 207 (Lindell); Ex. 320, Lindell Direct at 21.

construction, there is no reason to depart from its longstanding, Commission-approved method.

As discussed in Ms. Perkett's Direct Testimony, the Company's methodology to calculate AFUDC is the same as used in every rate case since 1977.[309] The Company's calculation of the AFUDC rate then and now was calculated 'in conformance with FERC Order 561 issued February 2, 1977.'"[310] This methodology assumes "that a utility's short-term debt is the first source of funds used for financing construction. The remainder of the construction is assumed to be financed out of long-term debt, preferred stock, and common stock equity on the basis of these funds as they existed at the end of the prior year."[311] Mr. Lindell acknowledges this formula, and that one of the purposes of the FERC-established AFUDC formula is to assure uniformity in the calculation of AFUDC by all utilities.[312] Nonetheless, he suggests that equity should not be used in the calculation of the rate based on the assumption that cash from operations will fund projects, and that a simple average of short- and long-term debt should be used instead of the FERC weighted average.[313]

This approach would not only change decades of Commission precedent and be inconsistent with FERC policy and practice, but would also substantially lower the Company's AFUDC rate. Mr. Lindell testified that the Company's AFUDC rate would be reduced from 6.792 percent as calculated in compliance with FERC's requirements, to 2.62 percent.[314] Although he opines that Company shareholders would view this rate as reasonable, he offers no basis for that opinion.[315] He also

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[309] Ex. 92, Perkett Direct at 57.
[310] 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)).
[311] Ex. 92, Perkett Direct at 56 (quoting Robert L. Hahne & Gregory E. Aliff, *Accounting for Public Utilities,* vol. 1, § 4.04[5][b], 4-25 (Lexis, Nov. 2012)).
[312] Tr. Vol. 3 at 209 (Lindell).
[313] Ex. 320, Lindell Direct at 28.
[314] Ex. 320, Lindell Direct at 28.
[315] Tr. Vol. 3 at 203 (Lindell).

offers no basis for using a simple, rather than weighted, average of short- and long-term debt. Finally, although Mr. Lindell would require "a clear showing [which] would be an issuance of equity to fund a large project," he acknowledges that "you can't trace funds" used to finance capital projects.[316] In other words, there is no support for basing the AFUDC rate calculation on an assumption that equity is never used in construction financing, nor for assuming that short-term and long-term debt are used equally regardless of circumstances.

Fundamentally, the FERC formula for calculation of the AFUDC rate correctly reflects the use of short term debt to fund construction, and that once available short term debt is exhausted all long-term capital will be applied to fund the investment.[317] Likewise, the Company's capital structure is specifically designed to provide the appropriate mixes of capital to fund all capital needs.[318] Consequently, it would be inappropriate to adopt an AFUDC rate formula that is inconsistent with this capital mix, with the FERC method for calculating the AFUDC rate, and with this Commission's longstanding precedent.

4. No Proposed Minimum for Projects in CWIP is Warranted

The second Commission's requirement with respect to CWIP and AFUDC accounting is that the Company must "address whether a minimum dollar level should be set for projects in CWIP."[319] 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 additional cost of accumulated AFUDC

[316] Tr. Vol. 3 at 212, 213 (Lindell).
[317] Ex. 94, Perkett Rebuttal at 28.
[318] Ex. 94, Perkett Rebuttal at 28.
[319] Order at 54, Docket No. E002/GR-12-961.

> for projects that should be considered in service almost immediately.[320]

Given this balance, no threshold for projects in CWIP is necessary.

Mr. Lindell argues, however, 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."[321] This supposition 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.[322] 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.[323]

Further, 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.[324] 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."[325] 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.

The OAG suggests that other jurisdictions have limitations similar to the OAG's recommended $25 million threshold, but offers Florida as its only example.[326] The OAG contends that "administrative rules in Florida only allow CWIP projects to accrue AFUDC if they exceed one half of one percent of total plant in service."[327]

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320 Ex. 92, Perkett Direct at 64.
321 Ex. 320, Lindell Direct at 28; Ex. 323, Lindell Surrebuttal at 2.
322 Ex. 94, Perkett Rebuttal at 30.
323 Ex. 94, Perkett Rebuttal at 31.
324 Ex. 92, Perkett Direct at 29.
325 In *Northern States Power Co.*, 17 FERC ¶ 61,196, at 61,382-83 (1981) (Opinion No. 134).
326 Ex. 323, Lindell Surrebuttal at 15.
327 Ex. 323, Lindell Surrebuttal at 15.

However, Mr. Lindell admitted during hearings that he has never reviewed the Florida rule[328] and that he is not suggesting that Florida rules should apply in Minnesota.[329]

In fact, in Florida all projects completed within one year and costing less than 0.5 percent of the balance of Plant in Service are placed in CWIP and earn a current return.[330] Mr. Lindell's interpretation is based on a FERC Order Approving Uncontested Settlement attached as Schedule JJL-1 to his Direct Testimony, which notes that "in the event that projects receive CWIP in rate base treatment for wholesale rates but AFUDC treatment for retail rates, it will identify… the amount of AFUDC accrued in accordance with state rules that is excluded from wholesale rates."[331] The portion of the Order Mr. Lindell underlines reference Florida rules that "restrict AFUDC capitalization to very large projects built with estimated costs that exceed one half of one percent of total plant in service"[332] – which, in Florida, is simply an alternative to including CWIP in rate base (*i.e.,* with a current return and no AFUDC offset).[333]

Indeed, the Florida Public Service Commission has noted that "the inclusion of CWIP (not eligible for AFUDC) in rate base is consistent with our practice."[334] Thus Florida rules do not limit project eligibility for CWIP in the manner the OAG suggests, but rather typically include CWIP in rate base for projects up to a certain size and implementation period, after which AFUDC accrual may be applied. If the Florida ratemaking process were applied to Mr. Lindell's proposal, utilities would earn a current return during construction on all projects costing less than $25 million and AFUDC would accumulate for deferred recovery on projects costing more than $25

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328 Tr. Vol. 3 at 206 (Lindell).
329 Tr. Vol. 3 at 205 (Lindell).
330 Florida Rule 25-6.0141 (Allowance for Funds Used During Construction).
331 Ex. 324, Lindell Surrebuttal Schedule JJL-1 at 3.
332 Ex. 324, Lindell Surrebuttal Schedule JJL-1 at 3.
333 Florida Rule 25-6.0141 (Allowance for Funds Used During Construction).
334 In re Petition for Increase in Rates by Gulf Power Co., FINAL ORDER GRANTING IN PART AND DENYING IN PART PETITION FOR RATE INCREASE AND APPROVING STIPULATIONS AT 3, 4, Docket No. 1110138-EI (April 3, 2012).

million. Given that the Commission's current approach is consistent and balanced, no threshold is needed.

5. AFUDC Accounting for the Prairie Island EPU was Appropriate

The OAG also suggests that the Company should not have accumulated AFUDC for the Prairie Island EPU project during 2011 or 2012, because "[b]eginning in 2011, the project was no longer viable and ongoing" as required by FERC Accounting Requirement AR-5.[335] Mr. Lindell misconstrues both the FERC accounting rules on this subject and the nature of the Prairie Island EPU ramp down.

As discussed in Ms. Perkett's Rebuttal, a project's costs incurred up until the time of abandonment would accrue in AFUDC.[336] This is borne out by FERC decisions in two cases referenced in Ms. Perkett's Rebuttal. First, In *Boston Edison Company*, Pilgrim II, a nuclear generating unit, had its inception in 1972. Boston Edison formally announced the project's cancellation on September 23, 1981. Various other parties argued that the plant should have been cancelled, or at least considered cancelled, earlier. FERC determined that under AR-5, Boston Edison was entitled to recover AFUDC until the cancellation of the project on September 23, 1981:

> Accounting releases are informal interpretations of the Uniform System of Accounts to be followed in the absence of specific references in the accounting regulations and other authoritative decisions of the Commission. Significantly <u>AR-5 allows interest to continue even if an interruption in construction occurs if the interruption is reasonable under the circumstances.</u> In *Northern States Power Co.*, 17 FERC ¶ 61,196, at pp. 61,382-83 (1981) (Opinion No. 134), the Commission emphasizes that all components of AFUDC including the common equity portion are proper construction costs just as are tangible parts and material costs, and that the accruing of AFUDC should continue as long as the project is viable and ongoing. *See also Pennsylvania Power Co.,* 26 FERC at p. 61,785, where the same result was reached.[337]

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[335] Ex. 323, Lindell Surrebuttal at 22.
[336] Ex. 94, Perkett Rebuttal at 34.
[337] Docket No ER84-705-0500, 34 FERC63,023; 19876 FERC Lexus 3524 (emphasis added).

Second, the *Northern States Power Co.* ruling cited by FERC in *Boston Edison* dealt with the cancellation of the NSPW Tyrone nuclear plant, for which FERC ruled that NSPW could accrue and recover AFUDC until the project was cancelled:

> Prior to when a project is abandoned, it is clear that the 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….Were we to also require the shareholder to shoulder part of the AFUDC, it is clear that the risk of investing in electric utilities would be increased and the cost of capital would increase to the extent necessary to compensate for the additional risk.[338]

This precedent underscores that AFUDC accrual is appropriate through project cancellation, even where there is a period of interruption. The OAG's assumption that a project is not viable and ongoing simply because stakeholders must take time to determine whether to continue the project is contrary to this precedent.

Furthermore, in advocating that no AFUDC should have been accrued for the Prairie Island EPU during 2011 and 2012, Mr. Lindell misconstrues the circumstances of that Project. As discussed in detail by Mr. McCall's and Mr. Alders' Direct Testimony and underscored during the hearings, activities furthering the Prairie Island EPU continued appropriately through 2011 and 2012.[339] The circumstances causing a Notice of Changed Circumstances unfolded over the course of 2011, during which the Company continued assembly of a License Amendment Request package consistent with our obligations under the Certificate of Need and pre-established contracts. While Project costs were reduced toward the end of 2011, activities under the Westinghouse contract continued through the summer of 2012 for two primary reasons: (1) The Prairie Island project remained viable, and in fact there was no time

[338] 17 FERC at p. 61,383.
[339] Ex. 49, McCall Direct at 35-36.

at which it was clear it should be cancelled;[340] and (2) It was more prudent to continue the Westinghouse contract and receive the final deliverables – especially if the Project continued as expected – than to cancel the contract, pay a termination fee, and receive no deliverables.[341] Finally, the Project was not formally cancelled until February 2013, when the Commission its Order Terminating the Certificate of Need Prospectively.[342] By that time, the Company had already terminated AFUDC accrual consistent with the Commission's vote on the matter in December 2012.[343]

Mr. Lindell's proposal that AFUDC should be disallowed for all of 2011 and 2012 essentially assumes the Project was cancelled at the beginning of 2011. This proposal is not consonant with the facts, as the first of the new circumstances had not yet fully emerged, let alone the full spectrum of considerations that evolved over the course of 2011 and 2012. It is also inconsistent with FERC precedent allowing AFUDC to accrue through cancellation to avoid unfairly burdening shareholders and increasing the risk of utility investment. As a result, the Company should be permitted to recover its AFUDC accrual.

6. Conclusion

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

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340 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.

341 Ex. 49, McCall Direct at 33-34, 38.

342 Prairie Island EPU Certificate of Need, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY, Docket No. E002/CN-08-509 (Feb. 27, 2013) (emphasis added).

343 Ex. 45, Weatherby Direct at 5.

Prairie Island EPU is consistent with both FERC requirements and the circumstances surrounding that project.

C. Depreciation Reserve (Issue # 9)

By undertaking a multi-year rate plan, the Company was presented with a unique opportunity to moderate the level of our rate requests over a number of years thereby balancing the need for cost recovery with more predictable and balanced rates for our customers.[344] To effectuate this opportunity, the Company proposed to accelerate the recognition of the "excess theoretical reserve"[345] which the Commission had authorized be amortized over eight years in the Company's most recent rate case.[346] The Company believes that this pool of funds is available to the Commission to utilize for rate moderation purposes in this case, and subsequent cases, as it deems appropriate.[347] However, the Company initially proposed to amortize the excess theoretical reserve in a pattern of 50% in 2014, 30% in 2015 and 20% in 2016.[348] This amortization pattern is intended to result in stable and predictable rate increases for our customers.[349]

As the instant rate case progressed, several parties provided comments with respect to the rate mitigation proposal.[350] Most notably, the Department proposed an alternative 50%-40%-10% amortization schedule to accelerate the benefits to the years at issue in this case.[351] In the alternative, the Department acknowledged that the

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344 Ex. 25, Sparby Direct at 27:21-24.
345 *See* Ex. 96, Robinson Direct at 29:18-30:7 (discussing concept and naming it "excess theoretical reserve").
346 Ex. 99, Clark Direct at 27:3-12. The Company also proposed utilizing the refunds of funds provided by the Department of Energy due to the settlement of litigation concerning nuclear storage. The use and amount of DOE funds to be utilized for rate moderation has been resolved between the Company and the Department. Ex. 450, Campbell Opening Statement at pp 3-4.
347 Ex 100, Clark Rebuttal at 40:23-41:7.
348 Ex 99, Clark Direct at 27:13-19. Current 2014 interim rates reflect the use of 50% of the excess theoretical reserve and any modification to that amount would result in an increase in rates. Ex. 431, Campbell Direct at 90:19-22.
349 Ex. 25, Sparby Direct at 28:25-27.
350 *See* Ex. 370, Lindell Direct at 11-16; Ex 429, Campbell Direct at 75-94.
351 Ex. 431, Campbell Direct at 94:14-15.

initially proposed 50%-30%-10% would also be reasonable.[352] Based on this, there is no challenge to the reasonableness of the Company's 50%-30%-20% proposal. The Company notes that this proposal would provide for some mitigation of the impacts of the rate moderation for 2014 and 2015 in 2016.[353]

The Company's original rate moderation proposal was based on the assumption that it would receive all of the rate relief requested in the 2014 test year, which would have the effect of mitigating our deficiency in 2015 due to the fact that the Company only requested rate relief for a partial amount of that deficiency. However, the Company's initial assumption no longer holds true. Consequently, there is less need for rate moderation in the 2015 Step year of our proposal, and for that reason the Company does not believe the Department's 50-40-10 consumption pattern should be preferred over the Company's 50-30-20 pattern.

With this in mind, and to the extent deviating from the 50-30-20 pattern is beneficial to preserve the availability of depreciation reserve for a future rate case, we believe that the 50%-0%-50% potential alternative rate moderation proposal presented by Company witness Mr. Clark may be of value for further consideration. This pattern accelerates the benefits of the excess theoretical reserve for our customers,[354] preserves a significant amount of this pool of moderation funds to offset the Company's deficiencies in 2016, and mitigates the effect of the bounce back in 2016 due to the consumption of the excess theoretical reserve in 2015.[355]

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352 *Id.*

353 Ex. 98, Robinson Rebuttal at 11:1-19:14. As discussed by Company witness Mr. Jeffery Robinson, the utilization of the excess theoretical reserve results in a "bounce back" in subsequent years due to the effects on the accumulated depreciation reserve and expense. *Id.*

354 Ex. 100, Clark Rebuttal at 41:9-42:5.

355 *Id.*

D. Nuclear Theoretical Depreciation Reserve (2014) (Issue 75)

1. Background

This issue pertains to XLI's proposal to reduce the Company's revenue requirement by accelerating amortization of a perceived nuclear depreciation reserve surplus to a five-year term. The Company and the Department both disagree with this proposal based on XLI's assumptions about the existence of a surplus, its calculation methods, and its recommendation to implement a five-year amortization period.

The Commission addressed important considerations regarding our theoretical reserves in Docket E002/GR-12-961, explaining the nature of depreciation reserves:

> Depreciation accounting permits a utility to recover, over the span of a tangible asset's useful life, the cost of the assets plus the cost of decommissioning the asset. For each type of utility asset, a utility recovers depreciation expense from ratepayers and records them into a depreciation reserve…. A utility must use straight-line depreciation—depreciating an equal amount of an asset's cost plus decommissioning costs in each year of the asset's probable service life—unless the Commission authorizes an exception.[356]

The depreciation a utility accrues over the course of an asset's life to cover the cost of the asset plus retirement costs is based on the expected useful life and estimated net salvage approved for the period the expense is recognized. 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."[357]

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 infer that

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[356] Order at 25, Docket No. E002/GR-12-961 (citing Minn. R. 7825.0500, subps. 6 and 7 and Minn. R. 7825.0700, subp. 1).

[357] Order at 26, Docket No. E002/GR-12-961.

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 immediately indicate that excess funds may exist. Rather, it would be rare for actual depreciation collected to precisely match the theoretical reserve, and the likely retirement and depreciation needs of a facility are based on current assumptions about future events. Therefore, it is not always clear when or to what extent a surplus reserve is "real."[358]

2. Treatment of Issue in Docket 12-961

In our prior rate case, XLI and the Chamber (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. 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."[359]

The Commission also rejected XLI's proposal with respect to nuclear production plant, "especially regarding Xcel's nuclear generating plants."[360] The Commission observed "the preponderance of the evidence indicates that these reserves appropriately reflect the cost of production plant retirements, including interim retirements, as explained by Xcel and the Department."[361] 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

358 Order at 29, Docket No. E002/GR-12-961 (finding "insufficient reason to conclude this [Company production plant] reserve has a surplus").
359 Order at 28, Docket No. E002/GR-12-961.
360 Order at 29, Docket No. E002/GR-12-961.
361 Order at 29, Docket No. E002/GR-12-961.

investments in its nuclear generators, increasing the amount of production plant it has to depreciate."[362] 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.[363]

3. Application to XLI Proposal

Although the Commission directed further discussion of the matter in this case, its policy considerations and much of the factual discussion in the Docket 12-961 Order remain applicable. To begin with, the preponderance of the evidence continues to counsel against assuming there is a surplus reserve that will not be needed. In this proceeding, the Company calculated a nuclear reserve surplus of $72.5 million for the Minnesota jurisdiction, but noted that the existence and amount of the calculation depends on several current assumptions including remaining life, interim retirements and removal, and net salvage.[364]

XLI agrees that assumptions are required, but contends that a surplus must exist in light of recent depreciation study results and that the Company's calculation of the amount of surplus is too low because: (1) the Company included future (post-test year) capital additions in remaining life values used in the theoretical reserve calculation; and (2) the Company's theoretical reserve amounts are calculated by account total rather than individual vintages.[365] XLI therefore proposes a surplus of approximately $208 million exists and should be accelerated.[366]

With that said, it is important to consider XLI's own acknowledgement that any reserve calculation is based on assumptions about future events, including what amount of reserve will be needed for future retirement.[367] Put differently, "the

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[362] Order at 27, 29, Docket No. E002/GR-12-961.
[363] Order at 29, Docket No. E002/GR-12-961.
[364] Tr. Vol. 2 at 67; Ex. 263, Pollock Surrebuttal at 11; Ex. 92, Perkett Direct at 50-51.
[365] Ex. 263. Pollock Surrebuttal at 11; Ex. 260, Pollock Direct at 13.
[366] Tr. Vol. 3 at 22-23 (Pollock).
[367] Ex. 263, Pollock Direct at 12.

'surplus' is only an estimate, not a guaranteed surplus."[368] Moreover, in contrast to a TDG surplus calculation, which is based on a grouping of many individual assets, the nuclear theoretical reserve consists of a limited number of plants with finite lives.[369] As such, the risk of overestimating a nuclear reserve surplus is much greater.

The parties also differ on their best estimate of what the surplus may be. XLI depends heavily on using plant vintages to calculate the reserve.[370] While the Company's methodology is similar, we do not believe it is appropriate to use vintages to determine depreciation expense for nuclear facilities because it is not the assets themselves that determine remaining lives; rather, these facilities are subject to operating licenses regardless of whether plant assets reach the end of their useful life.[371] Consequently, it is more accurate to base nuclear reserve calculations on reasonable assumptions about remaining operating license lives, where possible, than to develop a surplus calculation and propose accelerated amortization based on asset life regardless of licensing life.[372]

Furthermore, XLI contends the Company should not have included future interim capital additions in the theoretical reserve calculation. It is important to note, however, that we did not consider the need for future capital additions in determining the depreciation expense.[373] Rather, the Company considered the need for future capital additions and the overall impacts to current and future customers to present a realistic view of the impact of total depreciation expense over the remaining life of each plant.[374] In contrast, the Department notes that XLI's assumption that

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368 Ex. 434, Campbell Rebuttal at 2.
369 Ex. 92, Perkett Direct at 49.
370 Ex. 260, Pollock Direct at 17-18.
371 Ex. 94, Perkett Rebuttal at 9.
372 Ex. 94, Perkett Rebuttal at 9. Acknowledging that nuclear operating licenses can be extended, the Company proposed to discuss calculations of a nuclear reserve on the basis of reasonable extension period assumptions. However, XLI did not engage in such a discussion.
373 Ex. 94, Perkett Rebuttal at 10.
374 Ex. 94, Perkett Rebuttal at 10.

customers have overpaid in the past is incomplete, as it does not take into account the significant capital additions being placed in service during the multi-year rate plan.[375]

Amortizing the surplus back to customers over a five year period and recollecting that surplus over the remaining life, places a larger burden on future customers after the five year period because depreciation expense grows with future additions and will be even larger because of the reclamation of the surplus. The Company more properly considered the proper level of the existing reserve and the likely future impacts to customers for total depreciation expense.

Finally, the Company and Department on one hand, and XLI on the other hand, disagree with the policy basis for accelerating amortization of this surplus. Currently, this hypothetical surplus is being spread over the remaining life of the units through the depreciation method currently required by the Commission. In addition, as we stated in our last rate case, it would not be prudent to accelerate amortization of these costs when the Company has recently "made large investments in its nuclear generators, increasing the amount of production plant it has to depreciate."[376]

In light of the lack of certainty regarding the existence or amount of a nuclear theoretical reserve, the Company recommends no change in the Commission's historical treatment of the nuclear theoretical reserve.

E. Changes to In-Service Dates for Capital Projects (2014 and 2015 Step) (Issue # 11)

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. The Department's proposed adjustments are unwarranted because it is contrary to the test-year concept.

[375] Ex. 434 Campbell Rebuttal at 3.
[376] Order at 27, 29, Docket No. E002/GR-12-961.

1. The Department's Proposed Adjustment

The Department proposed adjustments[377] based on capital additions that were included in our initial filing that will not go into service in 2014 or 2015 as planned. 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.[378] 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.[379] 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.[380]

The Department's adjustment does not include capital project in-service dates that have also advanced, which would thereby increase the Company's revenue requirement. The evidence on the record demonstrates that just as project in-service dates are moving out of the test year, other projects must be advanced for similar reasons[381]

The Department did not accept this offset on the grounds that allowing additional capital projects into the rate case would unfairly burden parties and would not be in the public interest.[382]

2. The Test Year is Representative

This issue calls into question the Commission's fundamental principles of a representative test year. The Commission has previously explained the nature of the test year in this way:

> [T]he Commission has noted that isolated changes in test year data can skew the rate case process for or against the Company,

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377 Ex. 429, Campbell Direct at 153.
378 Ex. 429, Campbell Direct at 153 and Schedule NAC-28, p. 3.
379 Ex. 94, Perkett Rebuttal at 38.
380 Ex. 429, Campbell Direct at 153 and Schedule NAC-28, p. 3.
381 Ex. 429, Campbell Direct at Schedule NAC-28, p. 3.
382 Ex. 429, Campbell Direct at 153.

> 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.'[383]

During any given year, a company's expenditures and project changes are subject to some level of movement in order to allow the Company to react to changing conditions, address emerging needs, and prudently delay projects where appropriate.[384] The question is not whether a representative test year perfectly matches actual expenditures or in-service dates for any given year, but whether the test year is reasonably representative.

Here, especially given the dynamic nature of the utility business, a relatively small percentage of projects is moving outside the year in which they were originally planned.[385] Furthermore, the Company 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).[386] Treating changes in in-service dates as appropriate adjustments, based solely on the changes that would reduce the test year as of one point in time, is inconsistent with this concept. These un-rebutted facts and discussion explain why the Company's capital revenue requirement is

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[383] *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 4 (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,* Docket No. E-015/GR-87-223, ORDER AFTER RECONSIDERATION AND REHEARING (May 16, 1988)).
[384] Ex. 429, Campbell Direct at Schedule NAC-28, p. 4.
[385] Ex. 429, Campbell Direct at Schedule NAC-28, p. 4.
[386] Ex. 429, Campbell Direct at Schedule NAC-28, p. 4-6; Ex. 94, Perkett Rebuttal at 39-42.

representative at an overall level, consistent with the representative nature of the test year.

F. Interest Rate on Interim Rate Refund (Issue #66)

The interest rate required to be paid on interim refunds is set at prime rate under Minn. R. 7825.3300. 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). The OAG's position is based on the Commission's decision in the Company's last rate case, Docket No E002/GR-12-961.[387] The Company disagrees with the OAG recommendation for several reasons.

First, the Company believes the instant case is distinguishable from its last electric rate case and as a result the reasons for varying Minnesota Rule 7825.3300 are not present. Namely, the Company took a conservative approach with interim rates when compared to the interim rate calculation provided under Minnesota law. Specifically, the Company took steps to assure its interim rates would be approximately half of its requested rate increase for the test year. Additionally, the Company did not seek an interim rate increase for the 2015 Step Year. This is important because during the second year of the MYRP and before final rates go into effect, the Company will likely not be in a refund position or in a very small one.

Second, from a cost of service perspective, revenues from interim rates are equivalent to, and a trade-off for, short term borrowing.[388] Specifically, 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. This relationship leads directly to consideration of what is the cost of short term borrowing that is avoided by the interim revenues. That avoided cost is determined by the Company's cost of short term borrowing, which is 0.62 percent.[389] The Prime Rate,

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[387] Ex. 370, Lindell Direct at 58-59.
[388] Ex. 31, Tyson Rebuttal at 23-24.
[389] Ex. 31, Tyson Rebuttal at 24.

which is the rate the Company will pay on interim rate refunds pursuant to Commission rule, is 3.25 percent.[390] Accordingly, it is clear that under the Commission Rule, the Company the 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).[391]

The comparison to short term debt rates is further supported by the fact that interim rates are, on average, outstanding for less than 12 months. Interim rates began to be collected on January 1, 2014. If the interim rate refund is completed by September, 2015, the total period of the interim rate refund would be 21 months. However, some of the interim rate refunds would be returned in less than 1 month (those collected in September 2015) and some would have been outstanding for 21 months (those collected in January 2014). The average would be 10.5 months (one half of the 21 month period). A 10.5 month average outstanding time period is consistent with short term debt, which by definition has a term of less than one year.

Third the interim rate refund includes any expenses that were collected in excess of the expenses allowed in final rates along with a refund of any excess return on rate base, which already reflects the Company's overall rate of return.[392] Applying the overall rate of return to the refunds would be an unreasonable cost of service burden because: (1) the Company does not earn any return on expenses; and (2) the refund already reflects the Company's overall rate of return applied to disallowed rate base.[393]

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[390] Minn. Rule. 7825.3300
[391] Ex. 31, Tyson Rebuttal at 24.
[392] Ex. 90, Heuer Rebuttal at 38.
[393] Ex. 90, Heuer Rebuttal at 37-39.

G. Fuel Clause Adjustment Incentive (FCA)/Sherco 3 Fuel Costs (Issue # 67, 68)

XLI and MCC have raised the need for reforms of the Company's Fuel Clause Adjustment (FCA) mechanism.[394] Additionally, the Department has also identified an interest in reforms to the FCA.[395] Because the FCA is separate rate mechanism from the base rates which are the subject of the instant rate case, the Company believes that the appropriate proceeding in which to address FCA matters is in the Annual Automatic Adjustment (AAA) proceeding.[396] The Department agrees with the Company's position that FCA matters should be addressed in the AAA Docket.[397]

On a related note, MCC has proposed that the replacement fuel costs for Sherco 3 and Monticello be capitalized and recovered over the life of the respective plants.[398] Similarly to the concerns the Company has raised with respect to addressing FCA related issues in a rate case, the Company believes that these issues are most appropriately addressed in AAA proceedings.[399] The Department concurs with this assessment. [400]

H. Corporate Aviation (Issue # 65)

The Company has included approximately $954,000 in its 2014 test year cost of service for corporate aviation expenses.[401] This amount reflects fifty percent of the approximately $1.9 million of corporate aviation costs budgeted to be allocated to the Company during the 2014 test year.[402] This amount is reasonable, justified[403] and

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394 Ex. 260, Pollack Direct at 25:1-32:12; Ex. 343, Maini Direct at 41:12-43:6.
395 *See* Ex. 412, Ouanes Rebuttal at 16:8-20.
396 Ex. 100, Clark Rebuttal at 43:6-15.
397 Ex. 412, Ouanes Rebuttal at 15:12-13.
398 Ex. 340, Schedin Direct at 13:28-14:30, 9:8-13.
399 Ex. 94, Perkett Rebuttal at. 54:1- 55:3.
400 *See* Ex. 437, Lusti Direct at 68:9-11 (discussing the Sherco 3 replacement power costs are being addressed in the Company's current open AAA Docket).
401 Ex. 75, O'Hara Direct at 28:12-13.
402 Ex 75, O'Hara Direct at 28:10-11.
403 *See, e.g.*, Ex 75, O'Hara Direct at Schedule 10 (providing corporate aviation study).

consistent with Commission precedent.[404] Thus, the Company respectfully requests the ALJ and Commission authorize recovery of $954,000 for corporate aviation costs.

The evidence on the record demonstrates that corporate aviation provides benefits to the Company, as well as to its customers. Specifically, the efficiencies that result from the use of corporate aviation services results in increased productivity and cost savings.[405] The Company notes the State of Minnesota's analysis confirms these benefits of corporate aviation,[406] and is consistent with the Company's showing in previous rate cases.[407]

The OAG is recommending that the Company recover only two percent of its corporate aviation costs. To calculate this adjustment, the OAG arbitrarily determines that $300 is the cost per flight on the corporate aircraft and then multiplies that cost by the number of passengers per flight.[408] The OAG is also proposing additional adjustments for personal travel, flights coded as business area travel, and costs for investor relations and aviation use.[409]

The Company respectfully disagrees with the OAG's recommendations and believes the evidence on the record continues to support its proposal to recover 50 percent of its corporate aviation costs. Notwithstanding the fact that the OAG's $300 per flight approach has previously been rejected, it does not take into account

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[404] Ex. 77, O'Hara Rebuttal at 2:17:21 (citing to the Company's most recent rate cases in Docket No. E002/GR-10-971 and Docket No. E002/GR-12-961); Ex. 77, O'Hara Rebuttal at 3:7-10 (citing to past Minnesota Power rate cases in Docket Nos. E015/GR-08-415 and E015/GR-09-1151, and citing to past Otter Tail Power Company rate case in Docket No. E017/GR-10-239); *see also 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 OF LAW AND RECOMMENDATIONS at findings. 593-598, Docket No. E002/GR-12-961) (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).
[405] Ex. 75, O'Hara Direct at 30:22-25.
[406] Ex. 77, O'Hara Rebuttal at 4:5-13.
[407] *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 OF LAW AND RECOMMENDATIONS at finding 598 Docket No. E002/GR-12-961 ("[t]he Company's request is based on a detailed analysis of its costs, and properly considers increased productivity and employee time savings").
[408] *See* Ex. 370, Lindell Direct at 52:1-18.
[409] *See* Ex. 370, Lindell Direct at 57:14-58:6.

practical issues that affect ticket prices, different time periods between reservations and travel, and fees related to ticket changes and cancellations[410] nor does it account for increased productivity, time savings, avoided hotel charges, and any other benefit of corporate aviation.[411]

The OAG's concerns with personal travel costs are similarly misplaced. The flight logs show that the aircraft have the appropriate passengers on board and travel mostly between company locations. Personal travel is rare; 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.[412]

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.[413] The evidence on the record demonstrates the corporate plane trip legs were accompanied with a valid business purpose. The OAG has not articulated a situation where this is not the case.

Our corporate aviation service costs are a reasonable cost of service, as demonstrated by the Company on this record, and should therefore be recovered consistent with our request.

I. Rate Case and Monticello Prudency Review Expense Amortization (Issue #8)

The Company's test year includes expenses totaling approximately $950,000 to account for the cost of conducting the Monticello prudence investigation, as well as approximately $2.7 million in rate case expenses.[414] The Company proposed to amortize these costs over two years, consistent with the likelihood the Company will

[410] Ex. 77, O'Hara Rebuttal at 7:3-6.
[411] Ex. 77, O'Hara Rebuttal at 7:6-8.
[412] Ex. 77, O'Hara Rebuttal at 8:9-18.
[413] Ex. 77, O'Hara Rebuttal at 12:8-9.
[414] Ex. 90, Heuer Rebuttal at 23; Ex. 438, Lusti Direct at 28.

file its next rate case in late 2015.[415] The Department agreed with the amount of Prudence proceeding expense included in the test year and the amount and amortization of rate case expenses.[416] However, the Department proposes to amortize Prudence 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.[417]

The Company continues to believe that amortization of the prudence investigation over two years is the appropriate outcome. These costs are relatively small in amount and pertain to a one-time investigation.[418] In this way, the costs of a prudence investigation are similar to the costs of a rate case; a rate case proceeding may also have long-term financial effects on a utility, but amortization of rate case costs is typically limited to shorter periods to reflect the primary period affected by the proceeding. Along these same lines, it is arguably incongruent for the Department to suggest implementing any disallowance from the Prudence proceeding in one year, even though the disallowed amounts would reflect capital costs, while recommending recovery of smaller, shorter time-frame Prudence expenses over the life of the facility.

It is also important to note 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.[419] Finally, 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.[420] As a result, the Company

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[415] Ex. 90, Heuer Rebuttal at 24.
[416] Ex. 438, Lusti Direct at 28-29.
[417] Ex. 90, Heuer Rebuttal at 24; Ex. 442, Lusti Surrebuttal at 17-18.
[418] Ex. 90, Heuer Rebuttal at 25.
[419] Ex. 90, Heuer Rebuttal at 24.
[420] Ex. 90, Heuer Rebuttal at 24.

supports amortization of Monticello Prudence proceeding costs over a two-year period, consistent with the Parties' proposed amortization of rate case expenses.

J. Nuclear Refueling Outage Costs – Accounting Methodology (Issue # 64)

The Department initially recommended an adjustment to reduce the 2015 Step revenue requirement by $5.5 million.[421] That recommendation was based on the belief that the nuclear outage amortization costs were related to capital expenditures.[422] In Rebuttal testimony, the Company explained that the nuclear amortization expenses constitute a separate O&M expense, and that these costs are not capital-related costs. Further, the amortization of outage expense over an extended period of time recognizes the impact over the period of the refueling outage, and already provides the benefit of providing for a more normalized impact of outage costs for our customers. [423] As a result of the Company's explanation that the costs were not related to capital expenditures, the Department is no longer recommending a reduction in the nuclear amortization expense for 2015.[424]

The OAG, however, adopted the Department's initial recommendation and continues to make that recommendation.[425] The OAG argued that NSP has selectively identified costs that will increase in 2015 but did not recognize costs, such as nuclear refueling costs which decrease. The OAG also argued that nuclear refueling costs were like depreciation and were treated like nuclear plant costs because a deferral and amortization method was used.[426]

The OAG recommendation to reduce the 2015 Step by $5.5 million should be rejected. As the Company explained, and the Department recognized, nuclear refueling costs are not capital related costs. Further, the Company did not selectively

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421 Ex. 450, Campbell Opening at 1.
422 Ex. 450, Campbell Opening at 1.
423 Ex. 100, Clark Rebuttal at 3-4.
424 Ex. 450, Campbell Opening at 1.
425 Ex. 372, Lindell Rebuttal at 5-6; Ex. 141, Lindell Opening at 2.
426 Ex. 372, Lindell Rebuttal at 5-6.

accept 2015 cost increases and reject 2015 cost decreases. Rather, the Company applied an approach to present its 2015 Step request in a manner that is consistent with the MYRP Order. In addition, the Company has accepted adjustments that reduce our test year cost of service, which can carry through to the 2015 Step. Examples include nuclear fees and active health care.[427]

In addition, the Company explained that using the deferral and amortization method for these expenses promotes stability, predictability, and fairness for customers. Because nuclear refueling outage expenses can be substantial, this methodology moderates rate increases by phasing them in over a longer period of time. Further, refueling expenses can vary significantly from year to year depending on the number of outages per year. This methodology also moderates these variations. Finally, the deferral and amortization method matches the outage costs to the period during which the benefits from the outage occur.[428]

The OAG presented similar concerns regarding the deferral and amortization method in our 2008, 2010, and 2012 rate cases (Docket Nos.E002/GR-08-1065, E002/GR-10-971, and E002/GR-12-961). The Commission approved the deferral and amortization method in each of those cases.[429] In Docket E002/GR-08-1065 the Commission said:

> [Nuclear outage costs] are substantial, variable, and trending upward. They vary from reactor to reactor and over time. They occur at staggered intervals that can result in one, two, or three refueling shutdowns occurring in any given year. This essentially ensures inaccuracy in ratemaking. The purpose of this accounting change is to promote stability, predictability, accuracy and fairness; the Commission will monitor its performance in promoting these goals.[430]

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427 Ex. 100, Clark Rebuttal at 3-5.
428 Ex. 97, Robinson Rebuttal at 22.
429 Ex. 97, Robinson Rebuttal at 22.
430 *In the Matter of the Application of Northern States Power Co., d/b/a Xcel Energy for Authority to Increase Electric Rates in Minnesota,* Docket No. E-002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at p. 33 (Oct. 23, 2009).

The same advantages continue in the present case.

In the alternative, the OAG recommended that deferral and amortization could be used if the carrying charge was eliminated. The OAG argued that earning a return on a normal expense is inappropriate and provides an incentive for the Company to increase the scope of nuclear refueling outage costs.[431]

Contrary to the OAG position, when the Company uses funds to cover nuclear refueling outage costs prior to receiving funds from customers, fundamental rate making principles contemplate that the Company is entitled to earn a return on the unamortized balance net of accumulated deferred income tax.[432] Further, the Company uses its best efforts to implement sound accounting and budgeting principals to estimate our costs as accurately as possible, as this is in the best interests of the Company, our regulators, and our customers. In addition, the Company has an ongoing obligation to demonstrate that its nuclear refueling outage costs are reasonable and accurate.[433] Finally, although the OAG objected to our recovery of a carrying charge on the unamortized deferred balance in Docket E002/GR-12-961,. the Commission agreed with the Company that the rate of return represents the appropriate time-cost of money associated with these unamortized amounts.[434]

All of these factors support the Company's proposal regarding nuclear refueling outage amortization.

K. Black Dog 5/2 (Issue # 76)

1. Background

As part of its direct case, the Company presented information concerning an approximately three month outage at our Black Dog plant related to Units 2 and 5 ("Black Dog 5/2").[435] This outage occurred in late 2012 and early 2013 due to a

[431] Ex. 370, Lindell Direct at 44-47; Ex.373, Lindell Surrebuttal at 24
[432] Ex. 97, Robinson Rebuttal at 23-24.
[433] Ex. 97, Robinson Rebuttal at 24
[434] Ex. 97, Robinson Rebuttal at 24-25
[435] Ex 58, Mills Direct at 54:4-9.

bowed rotor, which occurred when the rotor was removed from its turning gear while hot due to human error.[436] The Company also presented information with respect to its efforts to mitigate future human error through the Human Performance Program portion of our Operating Model.[437] Although this program is relatively new, "human error contribution to these events has been trending down."[438] In response to the 2012-2013 outage at Black Dog 5/2, the costs of which were incurred outside of the test year,[439] and the general identification of the contribution of human error to plant performance, the Company is responding to human error issues through a thoughtful and comprehensive program. This is consistent with the prudent management of our generating fleet.[440]

Notwithstanding the Company's comprehensive response to address human performance issues on a fleet-wide basis, XLI seeks to impose a standard of perfection (and not prudence) on the Company and proposes an adjustment to the current test year as a punitive response to the 2012-2013 outage at Black Dog 5/2.[441] XLI is seeking to make an adjustment to O&M costs incurred outside of the test year and not included in the Company's current cost of service.[442] And, to the extent that XLI's proposed adjustment seeks to disallow certain capital costs, these costs are not related to capital additions being placed into service in the test year, but instead are merely embedded within rate base for the 2014 test year since the capital additions were made during the 2012-2013 outage.[443]

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[436] *Id.*
[437] Ex. 58, Mills Direct at 77:12-78:3.
[438] Ex. 58, Mills Direct at 77:26-27.
[439] Ex. 60, Mills Rebuttal at 17:1-15.
[440] *See* Tr. Vol. 2 at 15:3-16:10 (Mills) (describing how the appropriate standard for the management of generation resources is to respond to past events in a manner to mitigate their reoccurrence).
[441] Ex. 260, Pollock Direct at 24:1-7.
[442] *See* Ex. 60, Mills Rebuttal at 17:2.
[443] Ex. 60, Mills Rebuttal at 17:11-15.

XLI is imposing a standard of perfection, not prudence, on the Company and is seeking to engage in retroactive ratemaking. Consequently, XLI's proposed adjustment for the 2012-2013 outage at Black Dog 5/2 should be rejected.[444]

2. Prudence, Not Perfection

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.[445] The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all relevant circumstances.[446] The Company clearly acted prudently in light of the events at Black Dog 5/2.

Fundamentally, "it is not possible to completely eliminate human error."[447] The Company's conduct should be reviewed based on its response to any human error that occurred. With respect to Black Dog 5/2, since the Units came back on-line, "the plant has been operating well, and all of our performance indicators are improving and positive."[448] In fact, "[t]he project year-end equivalent availability factor … for 2014 is better than the previous 12 years."[449] Clearly the Company's response to an unfortunate human error event has resulted in improved performance based on the Company's prudent management of the plant.

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444 Both the Company and XLI agree that the matter of any replacement power costs incurred as a result of the outage should be handled in the appropriate AAA proceeding and not in this rate case.

445 *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").

446 *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).

447 Ex. 60, Mills Rebuttal at 16:25-26.

448 Ex. 60, Mills Rebuttal at 16:9-11.

449 Ex. 60, Mills Rebuttal at 16:11-12.

With that said, it is XLI's position that "any human error that results in incremental costs by the utility should be disallowed."[450] This is an impossible standard to meet and imposes a standard of perfection, not prudence on the Company. Consequently, XLI's proposed adjustment should be rejected.

3. Impermissible Retroactive Ratemaking

Accepting XLI's proposed Black Dog 5/2 adjustment would violate the "statutory policy requiring prospective, not retroactive, ratemaking."[451] This is because XLI is seeking the disallowance of costs that were incurred outside of the test year and not included in this rate case.[452] "Concern over the outage at Black Dog Units 5 and 2 was raised in our last rate case … and XLI had the opportunity at that time to address its concern of the costs of repairing the unit."[453] XLI is essentially seeking to reopen the last rate case and provide customers a discount for costs incurred outside of the test year and not in this case. "Reopening NSP's past rate cases to readjust rates to account for [the particular issue] would violate the long-standing and well-supported Commission policy against retroactive ratemaking."[454]

L. Capital Structure, and Costs of Short Term Debt and Long Term Debt (Issue #12)

1. Capital Structure

The Company and the Department recommend using: (1) the Company's updated capital structure for the 2014 test year ((52.50 percent Equity, 45.60 percent Long Term Debt (LTD), and 1.90 percent Short Term Debt (STD)); and (2) the Company's

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[450] Tr. Vol. 3 at 41:1-4 (Pollock).
[451] *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).
[452] Ex. 60, Mills Rebuttal at 16:3-5.
[453] Ex. 60, Mills Rebuttal at 17:3-6.
[454] *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).

updated capital structure for the 2015 Step (52.50 percent Equity, 45.61 percent LTD, and 1.89 percent STD).[455]

The Company's actual capital structure is appropriate for a number of reasons: (1) it is an actual, legally separate capital structure for the Company, which is a separate legal entity from its parent XEI and other XEI utilities and not simply an internal accounting structure; (2) the Company's actual capital structure provides the financial support for the Company's separate debt ratings and for the Company's $3.9 billion of outstanding publicly traded LTD securities(and the low cost of LTD) and is regularly reported to the Securities and Exchange Commission in filings related to the Company's publicly traded LTD;(3) the Company's equity ratio is needed to support its current debt ratings; and (4) the Company's actual capital structure is reasonable in comparison to other utilities.[456] The Company's 52.50 percent equity ratio is at the low end of the equity ratios needed to support its current A- debt rating from Standard and Poors (S&P) and is comparable to the 50.49 percent mean and 51.93 percent midpoint of Mr. Hevert's electric company group and the 52.33 percent mean and 53.13 percent midpoint of Mr. Hevert's combination company group.[457]

The Department supported using the Company's actual capital structure, noting that the Company is a separate legal entity with its own capital structure, and the Company issues its own debt securities which are rated by S&P and Moody's.[458] Further, while NSP's proposed equity ratio is somewhat higher than the average equity ratio for Dr. Amit's FECG, it is still a reasonable equity ratio.[459]

Mr. Glahn recommended use of the XEI consolidated capital structure with a 47.50 percent equity ratio for 2014 and 49.0 percent for 2015. Mr. Glahn asserted that

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455 Ex. 31, Tyson Rebuttal Schedules 3 and 7; Ex. 116, Tyson Opening at 1-2; Ex. 403, Amit Surrebuttal at 9-11.

456 Ex. 30, Tyson Direct at 9; Ex. 31, Tyson Rebuttal at4-7; Ex. 27, Hevert Direct at 53

457 Ex. 27, Ex. 27, Hevert Direct at 53.

458 Ex. 400, Ex. 400, Amit Direct at 45.

459 Ex. 400, Amit Direct at 50.

the Company was requesting recovery of its costs of common equity in greater proportion than is used to finance its operations.[460] Mr. Glahn also claimed that the Company is merely "an accounting fiction" unlike XEI which is "an exchange traded company" whose "actual equity/capital ratio can be directly observed."[461]

However, as Dr. Amit noted, Mr. Glahn failed to recognize that the Company has its own capital structure, issues its own long-term debt, and its common equity represents its accumulated retained earnings plus any net infusion of common equity capital from its parent which has its own separate capital structure. NSP's ratepayers must pay all prudent costs of serving them. These costs include NSP's cost of capital, which is appropriately calculated using NSP's own equity and long-term debt.[462]

Mr. Tyson reaffirmed that the Company has its own market based capital structure that supports its separate debt ratings and $4.2 billion of LTD securities.[463] The Company's equity ratio reflects actual equity investments and is managed to meet its credit ratings under rating agencies' financial requirements of rating agencies and its capital expenditures.[464] The Company's actual capital structure is directly connected to the Company's low cost of LTD and very favorable combination of long maturities and low rates.[465] Mr. Tyson also showed that Mr. Glahn's recommendation would impair market confidence in the Company.[466]

2. Costs of STD and LTD

The Company and the Department recommended that the Company's updated costs of LTD and STD be used for both the 2014 test year and the 2015 Step year.[467] For the 2014 test year, the costs are 4.90 percent for LTD and 0.62 percent for STD.

[460] Ex. 250, Glahn Direct at 26.
[461] Ex. 251, Glahn Surrebuttal at 6.
[462] Ex. 402, Amit Rebuttal at 14-15.
[463] Ex. 31, Tyson Rebuttal at 5.
[464] Ex. 31, Tyson Rebuttal at 5-11.
[465] Ex. 31, Tyson Rebuttal at 10, Schedule 2.
[466] Ex. 31, Tyson Rebuttal at 11.
[467] Ex. 31, Tyson Rebuttal Schedules 3 and 7; Ex. 116, Tyson Opening at 1-2; Ex. 403, Amit Surrebuttal at 9-11.

For the 2015 Step year, the costs are 4.94 percent for LTD and 1.12 percent for STD. No party disputed these costs.

3. Rate of Return

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.[468]

M. FERC Cost Comparison Study – KPI Benchmarks (Issue # 70)

The Company has demonstrated that its Key Performance Indicator (KPI) metrics are reasonable.[469] However, MCC and the Department have suggested that the Company include its relative performance as calculated in the Company's annual FERC Comparison Study (Study) as a KPI.[470] Because the Study is intended to benchmark the Company against all shareholder-owned utilities, it does not control for comparisons against non-similarly situated utilities and is therefore not an appropriate metric for our KPIs. However, the Company does utilize the study to determine if additional KPIs are necessary and has implemented them in response to the Study.[471] For these reasons, MCC's proposal should be rejected.

As part of the prudent management of our business, the Company conducts the Study which identifies Xcel Energy and its four operating companies' current cost structure relative to the operating companies of shareholder-owned utilities in the Edison Electric Institute Index.[472] 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.[473] Although the Study

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468 Ex. 31, Tyson Rebuttal at pp. 27-28; Ex. 116 Tyson Opening at pp. 1-2.
469 *See* Ex. 78, Figoli Direct at 42:23-44:24
470 Ex. 343, Maini Direct at 43:8-45:12; Ex. 412, Ouanes Rebuttal at 16:1-12.
471 Ex. 100, Clark Rebuttal at 46:2-18.
472 Ex. 100, Clark Rebuttal at 45:1-6.
473 *Id.*

provides useful comparisons with our peers, it is somewhat limited in that it does not provide reasons why an operating company's costs in certain areas might be higher or lower than that of other operating companies in the survey.[474] Consequently, the Study is useful for the Company to obtain an idea of how its operations compare to its peers, but the Study is not sufficiently complete as to allow the Company to draw reasoned conclusions with respect to its relative performance.

The 2013 Study identified two areas where the Company fell below the second quartile of its peers: non-fuel O&M and Transmission O&M. With respect to non-fuel O&M, the Company has implemented a KPI related to non-fuel O&M that is a more reasonable performance metric than the mere comparative analysis provided for in the Study.[475] The Company's KPI is an appropriate incentive because it takes into account the variation that may occur between cost categories and is tied to recoverable costs which directly impact our customers.[476] Conversely, the metrics in the Study may include some O&M costs that do not impact our customers. Additionally, the metrics in the Study do not provide a basis for us to understand why the Company ranks the way it does. Without the ability to know the underlying factors of the Company's relative rank in the Study, it is impossible for us to identify areas in which we need to approve. Consequently, the Study provides a poor metric with which to develop a KPI.

With respect to transmission O&M, because the Study results are influenced by multiple factors other than operational performance, MCC's suggestion to simply use the Study for benchmarking would not necessarily achieve the desired outcome of improved efficiency.[477] This is mainly due to the fact the specific transmission profile of a particular utility heavily influences their actual transmission O&M metrics rather

[474] Ex. 100, Clark Rebuttal at 45:8-11.
[475] Ex. 100, Clark Rebuttal at 46:2-8.
[476] Ex. 100, Clark Rebuttal at 46:10-12.
[477] Ex. 67, Kline Rebuttal at 39:6-11.

than their actual operating performance.[478] Based on this, the Study does not provide a reasonable way to measure our transmission O&M outside of a very high-level view. Because the Company's relative rank to its peers in the Study may be significantly influenced by factors beyond its control (such as RTO membership and service area density) it does not provide a reasonable metric for a KPI. Therefore, MCC's proposal should be rejected.

However, the Company has proposed that, to the extent the Commission orders the Company to include a transmission performance benchmark KPI, the benchmark should be against a more refined comparison group or be based on a more holistic set of metrics than those in the Study.[479]

N. Transmission Cost Controls (Issue # 69)

The Company has demonstrated that its transmission business unit has rigorous cost controls in place and that relevant personnel are held accountable for bringing in transmission projects on time and on budget.[480] Based on this, the Company posits that the concerns raised by MCC with respect to the management of the Company's Transmission Business[481] area are unfounded. The Company has also demonstrated that the MISO processes in place provide an opportunity for interested parties to review and challenge the Company's costs.[482] Therefore, MCC's proposal for the Company to initiate cost control mechanisms at MISO are similarly unfounded.[483]

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[478] Ex. 67, Kline Rebuttal at 40:21-44:13 (providing examples where the nature of the particular utility's transmission system, such as RTO membership or service territory density, affects its relative ranking in the Study without regard to its operating performance).

[479] Ex. 67, Kline Rebuttal at 44:15-45:2.

[480] Ex. 65; Kline Direct at 42:17-49-17 (describing the Transmission Governance Process for capital projects); Ex. 67, Kline Rebuttal at 29:19-33:13 (describing how each responsible employee is held accountable for their role in project management).

[481] Ex. 340, Schedin Direct at 19:24-30. The Company questions the appropriateness of utilizing the instant retail rate proceeding to attack the mechanisms in the MISO Tariff, a FERC filed tariff which is per se just and reasonable.

[482] Ex. 67, Kline Rebuttal at 37:3-8.

[483] Ex. 340, Schedin Direct at

MCC's recommendation for a strict cost cap for transmission projects based on the high-level cost estimates provided in the Company's Certificate of Need (CON) applications are also unfounded. The record reflects the fact that, at the time a CON is requested, there are significant uncertainties impacting final cost of a project that are not yet resolved and that can only be resolved once the final route of a transmission project is determined.[484] The record also reflects that the Company's cost estimation process is consistent with industry standards[485] and that this estimating process coincides with Minnesota's statutory transmission development scheme.[486] Consequently, "[i]mposing a cost cap at the CON stage of development is inconsistent with the purpose of the CON statute, which is to determine system need and the appropriate way to meet that need through a comparison of alternatives."[487]

Fundamentally, "the complexity of the transmission permitting, siting, routing and construction process and length of time required to complete projects weighs against imposing a cost cap at the very early CON stage of a transmission project."[488] The regulatory process has ample opportunities for parties to review and challenge the prudence of our development efforts when we seek recovery of these costs, either when we seek to include a project in the Transmission Cost Rider or when we seek to include them in base rates in a rate case. MCC witness "Mr. Schedin has not asserted that specific projects costs were not prudently incurred."[489] "We believe that our project management methods help to ensure that project costs are reasonable and prudent and we continue to bear the burden to make such a showing."[490]

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484 Ex. 67, Kline Rebuttal at 7:1-17:7 (describing the cost estimate development process for transmission projects).
485 Ex. 67, Kline Rebuttal at 7:7-9.
486 Ex. 67, Kline Rebuttal at 15:11-17.
487 Ex. 67, Kline Rebuttal at 19:12-14.
488 Ex. 67, Kline Rebuttal at 20:1-4.
489 Ex. 67, Kline Rebuttal at 20:10-11.
490 Ex. 67, Kline Rebuttal at 20:13-15.

IV. RATE DESIGN AND CCOSS

A. Background

Rate design primarily focuses on assigning revenue responsibilities to customer classes or rate groups within classes. 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. The Commission balances several factors in approving a rate design, including: "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."[491] Ultimately, the rate design process is a quasi-legislative function that largely rests on policy determinations.[492]

The major rate design issues in this case generally fall into three categories. First, parties differ as to the methodology used to measure the cost of providing service to each customer class. Second, parties disagree as to how closely rates should reflect the cost of service. Third, parties question the need to alter the Company's rate design in order to address conservation.

The Class Cost of Service Study (CCOSS) indicates the cost to serve each customer class and therefore assists the Commission in its efforts to set just and reasonable rates.[493] The record in this proceeding demonstrates that the Company's CCOSS is an appropriate ratemaking tool. The Company's rate design proposals balance cost and non-cost factors and result in an outcome that is both fair and appropriate given the facts of this case. Finally, the Company's proposed Revenue Decoupling Mechanism (RDM) removes the Company's disincentive to promote energy conservation and is a reasonable use of rate design to meet the State's energy

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[491] E002/GR-10-971 ORDER at 14.
[492] *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n,* 312 Minn. 250, 260, 251 N.W. 2d 350, 357 (1977).
[493] E002/GR-10-971 ORDER at 23.

policy goals. The Company requests approval of our proposed CCOSS, rate design and RDM.

B. Class Cost of Service Study

The 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. Overall, the CCOSS is designed to reflect cost causation, which assists in the development of just and reasonable rates.[494]

The Company, Department, OAG, MCC and XLI have all presented different CCOSSs in this case and have taken a variety of positions on CCOSS-related issues. As explained below, the Company's CCOSS is the most reasonable ratemaking tool for use in this case.

1. CCOSS Methodology

The Company performs a critical analysis of its CCOSS prior to filing each rate case. These analyses are 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. Ultimately, these refinements improve the measurement of cost causation.

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.[495] These two fundamental aspects of the CCOSS have been used by the Company with Commission approval for several rate cases.[496] The proposed CCOSSs

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[494] Ex. 102, Peppin Direct at 1-2; E002/GR-08-1065 ORDER at 44. *See also* E002/GR-10-971 ORDER at 23("Although a fully-embedded CCOSS may not be precise, it can be a useful tool for setting rates.").
[495] Ex. 102, Peppin Direct at 11-12.
[496] 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*, E001/GR-92-1185, FINDINGS OF FACT CONCLUSIONS OF LAW AND ORDER at 83-87 (September 29, 1993).

also include two changes approved by the Commission in the 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.[497]

Consistent with the refinement process described above, the Company's proposed CCOSS includes five refinements: 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. The last three refinements are unchallenged and should be adopted.

The Department and OAG disagree with the refinements related to Other Production O&M and Company-owned wind. Their disagreement is based, at least in part, on the Company's past support for alternative methodologies.[498] Yet, as discussed below, both refinements draw upon new information or analyses that ultimately provide a more accurate measurement of class cost responsibilities. Incorporating new or better information into the CCOSS process is neither novel nor inappropriate;[499] rather, it is part of each rate case and ultimately leads to a more accurate ratemaking tool.

2. Other Production O&M

Other Production O&M costs are production plant operations and maintenance expenses "other" than fuel and purchased power. In response to the Commission's Order in the 2013 rate case, the Company examined each of the 117

[497] Ex. 102, Peppin Direct at 11. The Company initially retained the allocation of CIP CCRC using the per kWh method approved by the Commission in the 2013 rate case, but in Rebuttal, agreed with the Department that CCRC costs and revenues should be removed from the CCOSS. *See* Ex. 103, Peppin Rebuttal at 2.
[498] Ex. 408, Ouanes Direct at 22-24, 34-35; Ex. 327, Nelson Rebuttal at 12-13, 17-18.
[499] Ex. 104, Peppin Surrebuttal at 6-8; Ex. 260, Pollock Rebuttal at 19.

cost items that make up Other Production O&M.[500] Based on the examination of each of the 117 cost items, the Company classified the Other Production O&M cost categories using a two-step process: first, Other Production O&M costs that varied directly with energy output (*i.e.* increase or decrease based on energy output) were classified as energy-related; second, the remaining costs were evaluated according to their predominant nature, as described in the NARUC Electric Utility Cost Allocation Manual, and classified as either energy-related or capacity-related.[501] The second step of the two-step process is referred to as the "predominant nature" method.[502] The predominant nature method, which is characterized as "common" practice in the NARUC manual,[503] represents a refinement of the classification of Other Production O&M and ultimately leads to a more accurate measurement of cost responsibility.

The Company's classification of chemicals and water use as being energy-related under the first step of the process described above appears to be unchallenged.[504] The Department and OAG, however, disagree with the Company's use of the predominant nature method to classify the remaining (i.e. non-chemicals and non-water) Other Production O&M costs. Both the Department and OAG recommend using the "location method" in the second step of the classification process.[505] The location method classifies the remaining Other Production O&M using plant type as a proxy, similar to what was performed in previous cases.

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500 *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)[*hereinafter* E002/GR-12-961 ORDER]; Ex. 102, Peppin Direct at 19 and Schedule 7.
501 Ex. 102, Peppin Direct at 22-25; Ex. 103, Peppin Rebuttal at 25 (citing page 66 of the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual (Jan. 1992)).
502 Ex. 103, Peppin Rebuttal at 25 (quoting page 66 of the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual (Jan. 1992)).
503 Ex. 103, Peppin Rebuttal at 25 (quoting page 66 of the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual (Jan. 1992)). The location method is characterized as "not standard practice" under the NARUC Manual. *Id.*
504 Ex. 408, Ouanes Direct at 35; Ex. 327 Nelson Rebuttal at 18; Ex. 343, Maini Direct at 25; Ex. 260, Pollock Rebuttal at 16-23; Tr. Vol. 4 at 100-101 (Ouanes).
505 Ex. 408, Ouanes Direct at 35; Ex. 327 Nelson Rebuttal at 18.

The Department and the OAG present two reasons for opposing the predominant nature method. First, both identify the Company's support for a different classification methodology in past cases as a justification for rejecting the Company's proposal in this case. This reasoning ignores the important fact that the Company's examination of each of the 117 cost items that make up Other Production O&M was a new analysis not previously performed in past cases.[506] The new analysis yielded better information regarding the nature of the Other Production O&M costs.

The Department contends the location method reasonably reflects cost causation because it reflects the allocation of the generation plants at which Other Production O&M costs are incurred.[507] When Other Production O&M costs are examined individually, however, it is clear the location method results in classifications that are inconsistent with cost causation. For example, under the location method:

- 100 percent of generation and equipment rentals that occur at Peaking plants are treated as capacity-related, even though a significant portion of the costs clearly change with the amount of energy produced; and
- Approximately 80 percent of the licensing fees, permits, regulatory expenses and association dues that occur at nuclear plants are treated as energy-related, but these costs do not vary with the amount of energy produced.

The locational method may have provided a reasonable approximation of causation in the absence of an examination of each of the 117 cost items that make up Other Production O&M, but the additional detail available in this case shows the predominant nature is superior.

The predominant nature method is supported by examination of each of the 117 cost items that make up Other Production O&M. The locational method is not

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506 Ex. 104, Peppin Surrebuttal at 8-9. The Department did not analyze the 117 cost items that make up Other Production O&M. Tr. Vol. 4 at 67-68 (Ouanes).
507 Ex. 414, Ouanes Surrebuttal at 8.

supported by examination of the different cost items, but rather relies on proxies.[508] The predominant nature method is "common" practice, while the locational method is "not standard."[509] And, as discussed above, it is normal to refine and improve the CCOSS when new information becomes available. For these reasons, the Company's proposed classification of Other Production O&M costs using the predominant nature method should be adopted.

3. Customer-Related Distribution Costs

The cost of primary lines, secondary lines, secondary transformers and service drops are classified as both demand- and customer-related costs in the Company's CCOSS. 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.[510]

The Company separates distribution costs into demand- and customer-related components using the Minimum Distribution System (MDS) method and has done so in each of its electric rate cases since at least 1985.[511]

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[508] The Department did not examine the cost items that make up Other Production O&M. Tr. Vol. 4 at 67-68 (Ouanes).
[509] Ex. 103, Peppin Rebuttal at 25 (quoting page 66 of the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual (Jan. 1992)).
[510] *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*, Docket No. E002/GR-91-1, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 74 (Nov. 27, 1991).
[511] 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*, Docket No. E002/GR-85-558, ORDER at 28 (June 2, 1986)(indicating the Company's CCOSS was performed using the MDS method)[*hereinafter* E002/GR-85-558 ORDER].

The OAG contends the MDS method overestimates customer-related costs and that the zero-intercept method is superior. The OAG's position is not supported by an actual zero-intercept study.[512] The position is contrary to accepted industry practice, which treats both the MDS and zero intercept as acceptable methods.[513] And the position is inconsistent with practice in Minnesota, as all Minnesota electric utilities either use the MDS method in their respective cost studies or have been ordered to do so in subsequent rate cases.[514] Thus, there is no support in the record, in industry practice or Commission precedent for adjusting the Company's CCOSS simply because it uses the MDS method.

Other justifications cited by the OAG similarly fail to support its recommended 10 percent adjustment. The Company explained, and the OAG eventually acknowledged, that the Company appropriately accounts for the minimum load associated with the minimum sized system.[515] The OAG is correct that if the Company's minimum system study was updated to reflect the Company's current minimum sized single-phase primary underground conductor, that, all else being equal, the portion of customer-related cost would decrease.[516] But the OAG ignores the fact that there are other types of equipment that, if also updated to reflect current

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[512] Tr. Vol 3 at 243-244 (Nelson).
[513] Ex. 143, Excerpts from the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual at 9 (page 90 of the manual)(stating the MDS method and zero-intercept method are the two methods for separating distribution costs into customer-related and demand-related components).
[514] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E017/GR-10-239, FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION at ¶ 481 (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*, Docket No. E001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS AND ORDER at Order Point 15.C. (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).
[515] Tr. Vol. 3 at 247-248 (Nelson).
[516] Ex. 328, Nelson Surrebuttal at 6-7.

minimums, would increase customer-related costs.[517] Selectively relying on one item while ignoring others leads to an arbitrary adjustment – a fact admitted by the OAG.[518] Previous Administrative Law Judges and Commissions have resisted the use of arbitrary adjustments when calculating customer-related distribution costs and this Administrative Law Judge and Commission should do so also.[519]

Finally, the Company has committed to refreshing its minimum system study prior to filing its next rate case. The refresh will reexamine all of the assumptions supporting 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.[520] 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.

4. Classification of Fixed Production Plant

The Company classifies fixed production plant into capacity-related and energy-related sub-functions using the Plant Stratification method.[521] The advantage of Plant Stratification is that it recognizes the duel benefits associated with baseload and intermediate generation resources. For example, a significant portion of the fixed

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517 Ex. 331, Nelson Trade Secret Surrebuttal Schedules at RN-11 (showing that materials cost of current minimum sized pole exceeds the installed cost (*i.e.* materials, plus labors and overheads) of minimum sized pole used in minimum system study); 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).
518 Ex. 325, Nelson Direct at 26; Tr. Vol. 3 at 249-250 (Nelson).
519 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.").
520 Ex. 103, Peppin Rebuttal at 31, 34-35; Ex. 104, Peppin Surrebuttal at 5-6.
521 Ex. 102, Peppin Direct at 12.

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.[522] Plant Stratification assigns a portion of the cost of these plants to energy and a portion to capacity. The Commission has cited this aspect of Plant Stratification with approval in the Company's previous rate cases,[523] and in several other recent electric rate cases.[524]

The MCC asks that the Plant Stratification method be replaced by the Straight Fixed-Variable (SFV) method.[525] MCC raises concerns related to price signals, load factors and the role of policy-based resources on the system as justifying a move to the SFV method.[526] The Company acknowledges the MCC's concerns, but the movement to the SFV method would be a significant departure from past precedent and would lead to a significant shift in inter-class cost responsibilities.[527] Further, the SFV method does not reflect the dual nature of baseload and intermediate fixed production plant.[528] The Company requests the Commission approve the use of the Company's Plant Stratification methodology in this case.

XLI does not challenge the use of the Plant Stratification method, but instead presents a fundamental change to how Plant Stratification works.[529] Specifically, XLI proposes to revise the Plant Stratification calculation in two ways: 1) to 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

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522 Ex. 102, Peppin Direct at 13-14.
523 E002/GR-10-971 ORDER at 20; E002/GR-08-1065 ORDER at 44.
524 E001/GR-10-276 ORDER at 50.
525 Ex. 343, Maini Direct at 19.
526 Ex. 343, Maini Direct at 17-19; Ex. 345, Maini Surrebuttal at 12-13.
527 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.
528 Ex. 103, Peppin Rebuttal at 10.
529 Ex. 260, Pollock Direct at 33, 36.

current-dollar replacement costs for each plant type with depreciated replacement values.

Table 1
Comparison of Plant Stratification Calculations

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

The table above shows the fundamental flaw in the XLI's proposal, namely that unlike the Company's methodology, XLI does not rely on an apples-to-apples comparison between numerator and denominator costs.[530] 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.[531] The XLI's proposal is invalid and should not be adopted.

5. Company Owned Wind

The other refinement at issue in this case is the treatment of four Company-owned wind projects in the CCOSS. The Company proposes that the CCOSS reflect the differences in cost-causation between Nobles and Grand Meadow on the one hand and Borders and Pleasant Valley on the other. Nobles and Grand Meadow were acquired to fulfill the Company's Renewable Energy Standard (RES) obligations.[532]

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530 Ex. 103, Peppin Rebuttal at 11-12; Ex. 412, Ouanes Rebuttal at 10-11.
531 Ex. 103, Peppin Rebuttal at 11-12; Ex. 412, Ouanes Rebuttal at 11.
532 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*

Borders and Pleasant Valley were acquired to minimize system costs, consistent with how other fixed production plant is added to the system.[533] The Company believes these differences in cost causation provide a policy justification for differing treatment within the CCOSS.

Neither the Department nor the OAG accept that the difference in cost-causation between Nobles and Grand Meadow and Borders and Pleasant Valley should be reflected in the CCOSS. The Department and OAG partially rely on the Company's position in past cases regarding the classification and allocation of Company-owned wind. Similar to positions taken regarding Other Production O&M, relying on past treatment fails to account for new information presented in this case – that there is a clear and identifiable difference between resources acquired to minimize system costs (Borders and Pleasant Valley) and resources that were added to meet policy mandates (Nobles and Grand Meadow). Now that this distinction is identifiable, it is reasonable for the Commission to make a policy determination that reflects cost-causation, consistent with the quasi-legislative nature of the rate design process.

At this point, parties appear to agree that it would be reasonable to apply the Plant Stratification methodology to Borders and Pleasant Valley,[534] leaving the

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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)).

533 *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.").

534 The OAG identifies plant stratification as "an acceptable method," though it supports a 100 percent energy classification as being most appropriate. *See* Ex. 327, Nelson Rebuttal at 13.

treatment of Nobles and Grand Meadow in controversy. The four different proposals are summarized below.

Table 2
Percentage of Nobles and Grand Meadow Costs Allocated to Classes[535]

	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%

The theory behind each of the methodologies offered is not a perfect fit for the policy-based cost-causation associated with Nobles and Grand Meadow.[536] Therefore, the Commission's focus should be on the ultimate cost allocations. The Company's proposal results in a reasonable cost allocation that is more consistent with the policy-based nature of the Nobles and Grand Meadow projects and should be adopted.

6. Calculation of the D10S Capacity Allocator

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.[537] The OAG asserts the allocator should be calculated using each

535 Ex. 103, Peppin Rebuttal at 22.
536 For example, the Company explained the underlying theory behind Plant Stratification is not consistent with the decision-making that supported the Nobles and Grand Meadow project. *See e.g.*, Ex. 102, Peppin Direct at 27-28; Ex. 103, Peppin Rebuttal at 19; Ex. 260, Pollock Rebuttal at 7-9. The Company also explained that a 100 percent energy allocator did not reflect cost causation because if the Company was only interested in acquiring energy, and not energy that complied with the RES, then it may have pursued other options. Ex. 103, Peppin Rebuttal at 19. Finally, the Company acknowledged that wind was generally seen as an energy resource. Ex. 103, Peppin Rebuttal at 18.
537 Ex. 103, Peppin Rebuttal at 37.

class's load at the hour of the MISO peak, not the Company's peak.[538] Mr. Peppin 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.[539] Thus, the OAG's proposed calculation is not feasible and an order requiring the Company to calculate the D10S capacity allocator based on MISO's peak could not be accomplished. The OAG's recommendations on this topic should not be adopted.

7. Allocation of Economic Development Discounts

The Company's economic development programs are designed to attract and retain large customers.[540] In the 2013 rate case, the Commission decided that all classes should share in the cost of these discounts, but ordered the Company to provide additional information in this case regarding the appropriate cost allocation.[541] In response, the Company evaluated different allocation options in its Direct Testimony;[542] the Department and OAG have recommended an additional option.[543]

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538 Ex. 325, Nelson Direct at 13; Ex. 328, Nelson Surrebuttal at 13.
539 Ex. 103, Peppin Rebuttal at 37-38.
540 Ex. 102, Peppin Direct at 19; Ex. 103, Peppin Rebuttal at 41; Ex. 260, Pollock Rebuttal at 22-23; Ex. 345, Maini Surrebuttal at 19.
541 E002/GR-12-961 ORDER at Order Points 34 and 57.
542 Ex. 102, Peppin Direct at 18.
543 Ex. 408, Ouanes Direct at 39; Ex. 325, Nelson Direct at 31.

Table 3
Comparison of Economic Development Discount Allocation Methods

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%

Similar to Company-owned wind, the appropriate allocation methodology for economic development discounts is a policy question within the quasi-legislative function. The Department and OAG recommend a narrowly-focused approach that considers *how* the economic development costs are incurred (*i.e.* on a per kWh basis) but ignores (or undermines) *why* they are incurred (*i.e.* to attract and retain large customers for the benefit of the system and customers). The overall allocation methodology should be consistent purpose of the discounts, as recommended by the Company, MCC and XLI.

8. Interruptible Credits

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.[544] As it has in past cases, the XLI asserts that the Company's treatment of interruptible credits in the CCOSS violates the matching principle.[545]

[544] Ex. 103, Peppin Rebuttal at 13.
[545] Ex. 260, Pollock Direct at 46.

The Commission has repeatedly found the Company is appropriately accounting for the cost of interruptible credits in the CCOSS,[546] and should do so again in this case.

C. Revenue Allocation

Allocating revenue to customer classes is not formulaic and requires a balancing of several factors.[547] 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."[548] These factors are applied to the specific facts of the case and do not favor one customer class over others.

The Company and Department have both distilled the factors identified by the Commission into rate design principles.[549] In applying their own principles, the Company and Department arrive 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 the allocation recommended by the Department. The MCC and XLI recommend allocating revenue to fully match cost responsibilities (as measured by their own CCOSSs).[550] The OAG recommends no change in the existing revenue apportionment because, according to the OAG CCOSS, the Residential class is at or very near cost.[551]

These differing positions result in the following recommendations of how to allocate the potential revenue increase in this case.

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[546] E002/GR-10-971 ORDER at 25; E002/GR-12-961 ORDER at Order Point 2 (adopting the findings, conclusions, and recommendations of the FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATIONS dated July 3, 2013 in Docket No. E002/GR-12-961, including ¶ 686 in which the ALJ concluded the Company's treatment of interruptible credits is reasonable).
[547] *St. Paul Area Chamber of Commerce,* 312 Minn. at 260.
[548] E002/GR-10-971 ORDER at 14.
[549] Ex. 105, Huso Direct at 4-5; Ex. 420, Peirce Direct at 2.
[550] Ex. 345, Maini Surrebuttal at 20-21; Ex. 260, Pollock Direct at 37-38, 47.
[551] Ex. 325, Nelson Direct at 38-39.

Table 4
Comparison of Recommended Allocations of Proposed Revenue Increase[552]

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%	*	*

Under these recommendations, classes end up with revenue increases that may be higher or lower than the total increase, which is a reflection of both the recommended movement toward cost and each party's underlying view on the cost of service.

552 Ex. 107, Huso Rebuttal at 5, Tables 3 and 4; Ex. 422, Peirce Surrebuttal at 3-4, Tables 3 and 4; Ex. 325, Nelson Direct at 39, Tables 9 and 10; Ex. 328, 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.

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 a moderated movement to cost would maintain rate continuity. Also, the Company refined its CCOSS as part of this case and moderation will allow those changes to be reflected in rates over time.[553] The MCC and XLI, however, do raise valid concerns regarding the competitiveness of our business rates.[554] Uncompetitive business rates ultimately harm all customers through decreased future sales that can produce a need for future rate increases.[555] Thus, there is a real need to strike a reasonable balance among all the pertinent rate design factors that is fair to all classes. The Company's recommendation strikes this balance and should be adopted.

As in the Company's last two rate cases, the proportional approach should be used to allocate the actual revenue requirement approved by the Commission to the customer classes.[556] This approach is endorsed by the Department.[557]

D. Rate Design Proposals

1. Customer Charge

The Company and Department propose improve fairness among customers by moving Residential and Small General Service customer charges closer to the cost of service.[558] The OAG, CEIs, ECC and AARP oppose any increase in customer charges.[559]

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553 Ex. 105, Huso Direct at 9-10.
554 Ex. 343, Maini Direct at 30-34; Ex. 260, Pollock Direct at 39-40.
555 Ex. 343, Maini Direct at 33.
556 Ex. 105, Huso Direct at 12-13.
557 Ex. 420, Pierce Direct at 11.
558 Ex. 105, Huso Direct at 15; Ex. 420, Peirce Direct at 12.
559 Ex. 325, 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.

Table 5
Comparison of Proposed Customer Charges

<table>
<tr><th>Service Category</th><th>Cost of Service[560]</th><th>Present Charge[561]</th><th>Company Proposed[562]</th><th>Department Proposed[563]</th></tr>
<tr><td>Residential Overhead</td><td rowspan="4">$15.70 (Average)</td><td>$8.00</td><td>$9.25</td><td>$8.50</td></tr>
<tr><td>Residential Underground – Standard</td><td>$10.00</td><td>$11.25</td><td>$10.50</td></tr>
<tr><td>Residential Heating – Overhead</td><td>$10.00</td><td>$11.25</td><td>$10.50</td></tr>
<tr><td>Residential Heating – Underground</td><td>$12.00</td><td>$13.25</td><td>$12.50</td></tr>
<tr><td>Small General Service</td><td>$16.65</td><td>$10.00</td><td>$11.50</td><td>$10.50</td></tr>
</table>

The Company's proposed customer charges are a moderate and reasonable movement towards cost and are consistent with recent Commission decisions – they should be adopted.

Minnesota law directs that rates shall not "be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers"[564] Like other rate design items, the customer charge is a zero-sum issue: when kept below cost, the fixed costs must be recovered in energy charges, resulting in significant over-payment by customers with above-average usage.[565] The Commission recently acknowledged the unfairness of

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560 Ex. 107, Huso Rebuttal at 29, Table 10.
561 Ex. 107, Huso Rebuttal at 25, Table 9.
562 Ex. 107, Huso Rebuttal at 25, Table 9.
563 Ex. 420, Peirce Direct at 12, Table 6.
564 Minn. Stat. § 216B.03.
565 Ex. 105, Huso Direct at 16; Ex. 420, Peirce Direct at 14. The Company and Department both explain that above-average usage can result from several non-conservation factors, including the number of household members, appliance choice, whether the customer works from home and ability to invest in conservation. *See* Ex. 105, Huso Direct at 16; Ex. 420, Peirce Direct at 15.

below-cost customer charges in its June 9, 2014 FINDINGS OF FACT, CONCLUSIONS, AND ORDER in Docket No. G008/GR-13-316, stating:

> 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.[566] (Emphasis added)

The Company's proposed customer charges similarly promote increased equity across the Residential customer population.

Minnesota law also requires that rates must be "just and reasonable."[567] In this case, the Company's proposed increase ($1.25 for Residential service; $1.50 for Small General Service) and the resulting customer charge levels are entirely consistent with the Commission's decision in the E008/GR-13-316 ORDER that a $1.50 increase was just and reasonable.[568] There is ample reason to find the Company's proposed customer charges are just and reasonable.

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566 *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].

567 Minn. Stat. § 216B.03

568 G008/GR-13-316 ORDER at 52 ("*A $1.50 increase in the monthly residential customer charge*—with a corresponding decrease in the per-therm charge—*is a reasonable step toward recovery of the residential class's fixed costs in the fixed charge while appropriately minimizing conservation disincentive and possible rate shock effects.* For these reasons, the Commission also concludes that the proposed $3 increases in the Commercial and Industrial classes are appropriate.")(Emphasis added).]

Finally, the Company's proposal is consistent with other considerations weighed and balanced by the Commission in the rate design process. For example, the Company's proposed customer charge leaves a reasonable amount of customer-related fixed costs in energy charges as a conservation incentive.[569] The Company and Department have also shown that low income customers exist across all usage levels, making a below-cost customer charge a questionable means of addressing affordability.[570] Ultimately, the Commission balanced these and other factors in the E008/GR-13-316 ORDER and found a $1.50 increase and a $9.50 customer charge level reasonably balanced the relevant rate design considerations.[571] The Company's proposal similarly strikes a reasonable balance and should be adopted.

2. Interruptible Rates

Interruptible service is an important part of the Company's overall service offering. In this case, the Company proposes 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.[572]

Table 6
Present and 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%

569 Ex. 105, Huso Direct at 16-18; Ex. 107, Huso Rebuttal at 32.
570 Ex. 105, Huso Direct at 18-21; Ex. 107, Huso Rebuttal at 31-33; Ex. 422 Peirce Surrebuttal at 4-5, 9-12.
571 G008/GR-13-316 ORDER at 52.
572 Ex. 105, Huso Direct at 26-28.

These increases in the interruptible rate discounts help offset recent and proposed demand charge increases and will improve the Company's ability to maintain an optimal supply of interruptible load.[573] The Company's proposed interruptible rate discount levels are reasonable and should be adopted.

The Department also agrees interruptible rate discounts should be increased, but only by three percent.[574] The Department bases its recommendation in part on the observation that the Company has not interrupted customers frequently in the past.[575] The Company, explained, however, that

> There are several supply and demand factors that affect the need to *use* interruptible load. Having the *option* to interrupt as conditions warrant can provide significant value, especially when supply and demand factors are quickly altered.[576]

The MCC and XLI made similar observations that the value of interruptible service stems from the option to interrupt.[577] Also, while the Department is correct that the Company's proposal is not expected to materially increase the amount of interruptible load,[578] the Company does expect the increase will help *maintain* an optimal supply of interruptible load.[579] Given the concerns raised by the MCC regarding customers dropping off interruptible service and the decrease in interruptible load since the Company's last rate case,[580] the slightly larger increase proposed by the Company is appropriate.

Though an increase above the Department's recommendation is warranted, the MCC and XLI proposals go too far. The MCC's proposal not is methodologically

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573 Ex. 105, Huso Direct at 27.
574 Ex. 420, Peirce Direct at 26.
575 Ex. 420, Peirce Direct at 26.
576 Ex. 107, Huso Rebuttal at 35-36.
577 Ex. 345, Maini Surrebuttal at 22; Ex. 263, Pollock Surrebuttal at 36.
578 Ex. 420, Peirce Direct at 25 (citing the Company's response to DOC-320, included as schedule SLP-9 to Ms. Pierce's Direct Testimony).
579 Ex. 105, Huso Direct at 27.
580 Ex. 345, Maini Surrebuttal at 24; Ex. 145, Mani Opening Statement at 1 and Attachment A (Company response to MCC-157).

correct because interruptible service is not a directly comparable substitute for physical generation and avoided costs cannot be directly applied to embedded cost rates.[581] The Company is also proposing to increase the Short Notice discount by an amount necessary to maintain the current premium over the Tier 1, Performance Factor level C option.[582]

The Company's proposed interruptible rate discounts strike a reasonable balance that should continue delivering value to all of the Company's customers.

V. TARIFF PROPOSALS

A. Coincident Peak Billing

The MCC proposes to amend the Company's service rules to facilitate coincident peak billing.[583] The Company estimated this change would impact *at most, nine customers*.[584] The MCC proposal is not consistent with established rate design, nor is it appropriate for distribution capacity costs.[585] While customers may be willing to pay the additional metering costs associated with the program,[586] the MCC has not addressed cost recovery for the associated billing process changes.[587] And, if the nine customers truly are interested in being billed on a coincident peak basis, they can modify their wiring configurations accordingly.[588] The MCC proposal should be rejected.

B. Definition of Contiguous

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,

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581 Ex. 107, Huso Rebuttal at 36-37.
582 Ex. 107, Huso Rebuttal at 37.
583 Ex. 340, Schedin Direct at 24-26; Ex. 342, Schedin Surrebuttal at 13-14.
584 Ex. 107, Huso Rebuttal at 43.
585 Ex. 107, Huso Rebuttal at 44.
586 Ex. 340, Schedin Direct at 25.
587 Ex. 107, Huso Rebuttal at 44.
588 Ex. 107, Huso Rebuttal at 43.

2nd Revised Sheet No. 19.3 of the Company's Electric Rate Book.[589] As discussed above, the MCC's coincident peak billing proposal is unreasonable, so no definition of the term is needed in that specific context. Minnesota law already addresses the definition of contiguous in the context of solar projects.[590] Finally, the Company provided its interpretation of the term contiguous as it appears in its tariff.[591]

C. Definition of Peak Period for Time of Day Rates

The on-peak period is currently defined as the weekday hours of 9:00 am though 9:00 pm except for seven specific holidays.[592] XLI proposes to limit the on-peak period for demand charges to summer months.[593] The Company's current seasonal demand charges reflect the cost difference associated with system seasonal peak capacity differentials, meaning no change is necessary.[594]

VI. DECOUPLING

Decoupling is a "regulatory tool designed to separate a utility's revenue from changes in energy sales."[595] Its purpose "is to reduce a utility's disincentive to promote energy efficiency."[596] The Company proposes to implement a partial revenue decoupling mechanism ("RDM") for its Residential and C&I Non-Demand customers.[597]

The Company's RDM is the first electric decoupling proposal made in this State. The Company therefore took a gradual and cautious approach.[598] Ultimately, the Company's proposal is reasonable and will contribute to the Commission's

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589 Ex. 340, Schedin Direct at 26; Ex. 342, Schedin Surrebuttal at 14-15.
590 Minn. Stat. § 216B.164, subd. 2a (e).
591 Ex. 136 (Company response to MCC-251).
592 Es. 107, Huso Rebuttal at 44.
593 Ex. 260, Pollock Direct at 58; Ex. 263, Pollock Surrebuttal at 39-42.
594 Ex. 107, Huso Rebuttal at 45.
595 Minn. Stat. § 216B.2412, subd. 1.
596 *Id.*
597 Ex. 109, Hansen Direct at 2, 9-19. The Company's proposed RDM is a "partial" decoupling mechanism because it excludes weather effects. *Id.* at 2.
598 Ex. 110, Hansen Rebuttal at 9, 13.

ongoing assessment of the merits of decoupling as a means of promoting energy efficiency and conservation.[599] The Company's RDM should be adopted.

A. Decoupling Policy

The OAG and AARP contend no decoupling mechanism should be adopted in this case.[600] Their opposition is based upon their view that the Company already has significant conservation incentives, making decoupling unnecessary.[601] This premise is faulty. The purpose of decoupling is to remove a utility's financial disincentive to promote conservation.[602] At the same time, the legislature has expressly authorized incentive mechanisms "to encourage the vigorous and effective implementation of utility conservation programs."[603] The statutory structure therefore treats decoupling and incentive mechanisms as complements, not substitutes.[604] The Commission has followed suit, approving decoupling for natural gas utilities with conservation incentive programs in place.[605] Commissions in other states have taken a similar approach.[606] The Company's proposal fits within the State's overall policy for pursuing energy savings and should be adopted.

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599 G008/GR-13-316 ORDER at 47.
600 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 4.
601 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 9-12.
602 Minn. Stat. § 216B.2412, subd. 1.
603 Minn. Stat. § 216B.16, subd. 6c.
604 The CEIs also view decoupling and incentive mechanisms to be complements. *See* Ex. 294, Cavanagh Rebuttal at 3-4.
605 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, 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. 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).
606 Ex. 109, Hansen Direct at 17 and Schedule 2.

The OAG and AARP also assert decoupling is inappropriate because it will increase costs without measurable benefits.[607] Similar arguments have been raised in the past and have been rejected.[608] Furthermore, while the proposed RDM may trigger rate decreases or increases in any given year, the Company will ultimately only collect the revenue per customer authorized in this case.[609] By definition, the revenue per customer established in this case will be set at a just and reasonable level,[610] meaning RDM adjustments should not be equated with adverse customer impacts. The Company also demonstrated: the level of potential RDM 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.[611]

Finally, the Company has included customer protection mechanisms as part of its proposal. For example, the Company proposes to cap annual RDM surcharges as a means of limiting volatility associated with the RDM.[612] The Company will also provide annual reports to the Commission on the RDM and has agreed the program should be a pilot.[613] These approaches help protect customers from potential adverse consequences of an RDM.[614] Accordingly, the Company's proposal is consistent with the statutory criteria and should be approved.

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607 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 9-11, 19-20.

608 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.")

609 Ex. 109, Hansen Direct at 9-11.

610 Minn. Stat. § 216B.03.

611 Ex. 109, Hansen Direct at 13 and Schedule 6; Ex. 110, Hansen Rebuttal at 6-11.

612 Ex. 109, Hansen Direct at 15; Ex. 110, Hansen Rebuttal at 9. Importantly, there is no limit on downward adjustments. Ex. 109, Hansen Direct at 15.

613 Ex. 109, Hansen Direct at 15; Ex. 110, Hansen Rebuttal at 2-4; Ex. 417, Davis Direct at 21-24.

614 G007, G011/GR-10-977 ORDER at 13 (finding annual reports and caps help mitigate adverse impacts associated with RDMs)

B. RDM Design

Several RDM design elements remain at issue in the case. As will be explained below, the Company's proposal is consistent with the statutory purpose of decoupling mechanisms and the Commission's ongoing evaluation of decoupling in this State. The Company's RDM design should be adopted.

The Company's RDM is a partial decoupling mechanism, meaning it excludes the effects of weather.[615] As proposed, the Company's RDM fulfills the statutory purpose of decoupling, namely to reduce the Company's disincentive to promote energy efficiency.[616] The Department and CEIs both agree the Company's proposal meets the statutory purpose of reducing the disincentive to promote conservation.[617] A full decoupling mechanism (that includes weather) would have no greater impact on reducing the Company's disincentive because weather is outside of the Company's control.[618] In terms of fulfilling the statutory purpose of decoupling, there is no reason to prefer full decoupling over partial decoupling.

The Department's preference for full decoupling is grounded in its assessment that partial decoupling could have an adverse impact on customers.[619] The Department's conclusion is problematic for several reasons. First, the inclusion or exclusion of weather has nothing to do with fulfilling the statutory purpose of decoupling: to reduce the conservation disincentive. The Department's analysis is also dependent on the pilot period sharing economic and weather characteristics with the recent past. The Company showed the purported advantages of full decoupling over partial decoupling either vanish or become disadvantages with simple changes in weather assumptions.[620] And the Department does not account for the Company's

615 Ex. 109, Hansen Direct at 2.
616 Ex. 109, Hansen Direct at 12.
617 Ex. 417, Davis Direct at 18; Ex. 290, Cavanagh Direct at 7; Tr. Vol 4 at 141-142 (Davis).
618 Ex. 109, Hansen Direct at 12; Tr. Vol 4 at 142 (Davis).
619 Ex. 417, Davis Direct at 32. The OAG agrees with the Department's assessment. *See* Ex. 327, Nelson Rebuttal at 38-39.
620 Ex. 110, Hansen Rebuttal at 5-8.

desire for a gradual approach,[621] nor the benefits associated with aligning program design with the Company's interests.[622] Finally, the Commission has approved both full and partial decoupling in the past, an indicator both may be acceptable.[623]

The Department, OAG and AARP all support a hard cap on potential RDM surcharges, not a soft cap as proposed by the Company.[624] A hard cap reintroduces a utility's disincentive to promote conservation.[625] It is therefore not surprising that most electric decoupling mechanisms have soft caps or no caps at all.[626] Also, the Department's concerns over a soft cap overlook the fact that the Company's proposal is subject to a true cap – the revenue per customer established in this case.[627] The soft cap acts a means of limiting the variability in customer rates.[628] Similar to its preference for partial decoupling, the Company's proposed soft cap is consistent with the purpose of decoupling and is reasonable overall; it should be adopted.

Remaining concerns associated with the Company's proposed RDM design have been addressed. The RDM is appropriately limited to the Residential and C&I Non-Demand classes because those two classes pay the highest portion of fixed costs through variable rates and therefore are associated with the highest conservation disincentive.[629] The focused approach is also consistent with Commission precedent

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[621] Ex. 109, Hansen Direct at 14; Ex. 110, Hansen Rebuttal at 9.
[622] Ex. 294, Cavanagh Rebuttal at 6.
[623] 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.").
[624] Ex. 417, Davis Direct at 38; Ex. 327, Nelson Rebuttal at 39; Ex. 311, Brockway Rebuttal at 3.
[625] Ex. 110, Davis Rebuttal at 10; Ex. 294, Cavanagh Rebuttal at 4-5.
[626] Ex. 110, Hansen Rebuttal at 10 (citing Ex. 109, Hansen Direct, Schedule 2). The Company's proposed cap level is also lower than typical caps for electric utilities. Ex. 110, Hansen Rebuttal at 12.
[627] Ex. 417, Davis Direct at 33; Ex. 109, Hansen Direct at 9-12.
[628] Ex. 110, Hansen Rebuttal at 11.
[629] Ex. 109, Hansen Direct at 13-14; Ex. 110, Hansen Rebuttal at 9, 13. The Company also explained application to the Residential and C&I Non-Demand classes is straightforward (due to rate design and weather normalization of energy) and avoids problems associated with the sales volatility seen in other classes. Ex. 109, Hansen Direct at 13-14; Ex. 110, Hansen Rebuttal at 12-13.

and the Company's overall preference for gradualism.[630] Removing the inclining block rate proposal from the case eliminates the need to change how the RDM adjustment is calculated.[631] Finally, the incremental complexity associated with adjusting the RDM for service outages is not justified.[632]

The Company's RDM is a gradual and reasonable first step on the path of electric decoupling in this State. The proposal reduces the disincentive to promote energy conservation. It includes customer protections and will provide an important reference point to assist the Commission in its ongoing assessment of decoupling as a regulatory tool. The RDM, as proposed by the Company, should be adopted.

VII. 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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[630] G007, G011/GR-10-977 ORDER at 14-15; G008/GR-08-1065 ORDER at 24.
[631] Ex. 135, Stipulation on Inclining Block Rates; Ex. 110, Hansen Rebuttal at 13-14.
[632] Ex. 110, Hansen Rebuttal at 15 (explaining that the Company considered methods for adjusting the RDM to account for sales lost during service outages, but concluded the additional complexity and uncertainty surrounding the calculation was not justified considering the limited revenue at stake).

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 23rd day of September 2014

/s/

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