STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergen	Commissioner

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-13-868

RESPONSE TO PETITIONS FOR RECONSIDERATION AND COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, respectfully submits this Response to the Department of Commerce and Office of Attorney General's May 28, 2015 Petitions for Reconsideration of the Minnesota Public Utilities Commission's May 8, 2015 Findings of Fact, Conclusions, and Order in this docket.[1]

In addition, the Department and OAG have recently raised new revenue requirement issues related to Sherco 3 insurance recovery and the calculation of the cost of debt for 2015 capital projects in compliance filings and letters, outside the reconsideration process. This approach is unusual, and we are concerned it may complicate the docket absent full record support or delay the resolution of this proceeding. Additionally, we are concerned that the Parties have also changed their positions on reconsideration and in their comments. Therefore, in the interest of efficiency, we address both the issues they raise on reconsideration and their comments related to Sherco 3 and the cost of debt calculation in this Response.[2]

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[1] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Services in the States of Minnesota*, Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, (May 8, 2015) (Order).

[2] We note that the Department also raised a true compliance issue – questions about implementation of our class cost of service – in a May 8, 2015 compliance filing. Because that issue does appear to fit the standard compliance process, we address it in our compliance filing dated May 29.

Overall, we believe the OAG and Department's petitions for reconsideration and proposals in new comments and compliance filings present no basis for the Commission to reconsider its Order. Although the parties propose some new accounting and reporting mechanisms, several of which are a departure from their previous positions, they illustrate no error of fact or law or other reason why the Commission should revisit issues considered thoroughly in initial deliberations and the Order. Accordingly, we respectfully recommend against adopting the parties' reconsideration and new proposals in compliance filings and comments.[3]

DISCUSSION

A. Standard for Reconsideration

Minnesota Statutes set forth the standard for the Commission's review of Petitions for Reconsideration: "If in the commission's judgment, after rehearing, it shall appear that the original decision, order, or determination is in any respect unlawful or unreasonable, the commission may reverse, change, modify, or suspend the original action accordingly."[4] The OAG and Department offer no information about lawfulness or reasonableness that the Commission has not already addressed. Rather, the parties repeat prior arguments or propose new, and some different, revenue recovery approaches based on other outcomes in these proceedings, after the record is closed. In such situations, no further consideration or reconsideration of the OAG and Department proposals is warranted.

In light of the new arguments made by various parties on reconsideration, it is important to clarify the difference between new information or erroneous information in an Order and simple requests that the Commission should reach a different conclusion. In particular, the OAG prefaces its request for reconsideration by noting that it has no new arguments or facts to offer and cannot identify any inconsistencies or other items the Commission did not previously consider in arriving at its Order. Rather, the OAG suggests that the Commission's precedent for denying requests for reconsideration has not stated "the proper context for reviewing a request for

[3] Several parties also provided additional comments with respect to our interim rate proposal. We believe our position on the appropriate interim rate outcome and support are thoroughly addressed in previous interim rate comments, and we need not reiterate them here. We note only that the Department's initial Comments concluded that the Commission had full discretion to adopt the Company's interim rate proposal in the context of a MYRP. Department Comments at 1 (Jan. 13, 2015). In more recent comments, the Department changes position to argue that the Commission needs to find exigent circumstances to support this proposal. Department Comments at 3 (May 28, 2015). We cannot identify the reason for this change.

[4] Minn. Stat. § 216B.27, subd. 3.

reconsideration"[5] because the Commission has only found that past petitions "'do[] not raise new issues, do[] not point to new and relevant evidence, [or do] not expose errors or ambiguities" in the Commission's decisions.'"[6] The OAG then argues for broader reconsideration where the OAG disagrees with an outcome.

However, the OAG's quotation of the Commission's bases for denying rehearing is selectively truncated, and as a result fails to illustrate that the Commission is simply not required to grant rehearing where it has already evaluated the arguments the parties are making and there is no error or inconsistency in the Order. Stated more completely, the Commission has said that "[b]ased on this review [of "the record and the arguments of the parties"], the Commission finds that the petitions do not raise new issues, do not point to new and relevant evidence, do not expose errors or ambiguities in the [] order, *and do not otherwise persuade the Commission that it should rethink the decisions set forth in that order.*"[7] In other words, in cases where rehearing has recently been denied, the Commission had thoroughly considered all facts and argument, arrived at a reasoned decision based on the record before it, and therefore had no reason to rehash the prior deliberation process.

Under this standard, neither the Department nor OAG have raised any new arguments that would merit reconsideration. Consequently, their Petitions should be denied.

B. Passage of Time (Department)

"Because this is the Commission's first chance to consider a multi-year rate-case proposal, novel issues unique to multiyear rate-setting are presented for the Commission's consideration."[8] The Department's proposed passage of time adjustment raised one of these novel issues during these proceedings: What is the appropriate treatment of the test year rate base in the Step year or years of an MYRP

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[5] OAG Reconsideration Petition at 2 (May 28, 2015).

[6] OAG Reconsideration Petition at 2 (May 28, 2015) (quoting *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider*, Docket No. G-002/M-14-336, ORDER DENYING RECONSIDERATION (Apr. 10, 2015); *In the Matter of the Petition of Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-011/GR-13-617, ORDER DENYING RECONSIDERATION at 1 (Dec. 22, 2014)).

[7] *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider*, Docket No. G-002/M-14-336, ORDER DENYING RECONSIDERATION (Apr. 10, 2015); *In the Matter of the Petition of Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-011/GR-13-617, ORDER DENYING RECONSIDERATION at 1 (Dec. 22, 2014) (emphasis added).

[8] Order at 24.

when a utility cannot request its full cost of service in those years under the Commission's MYRP Order.[9]

The Company believes that the ALJ and the Commission both reached the appropriate outcome with respect to the passage of time. Namely, while a passage of time adjustment may be appropriate in future rate cases, the facts surrounding this case do not support the Department's proposed adjustment.[10]

The Department raises no new facts or other information to support its continued insistence on a passage of time adjustment; however, its rationale supporting its proposed adjustment continues to evolve to attempt to justify a downward adjustment to the Company's 2015 revenue requirement. This is reason alone to deny the Department's requested reconsideration on the passage of time. Even if the Commission chooses to entertain the Department's request, it should still result in the same outcome that the Commission reached in its Order – namely, the Department's passage of time adjustment, no matter how argued by the Department, results in an increase in 2015 rates that is inappropriate in this case.

1. No Passage of Time Adjustment is Warranted

At the outset, we recognize that the passage of time concept raises new issues as part of the first MYRP rate case in Minnesota. Stated as simply as possible, the Department argues that due to the passage of time, "the Company's 2015 revenue requirements should be reduced by updating the entirety of the Company's 2014 rate base in 2015 to reflect accumulated depreciation *and* depreciation expense for the out-years of the Company's MYRP."[11] Although the Department's position has evolved throughout the case, the Department's position on reconsideration is essentially the same as its initial position: a passage of time adjustment should be made for the entirety of the Company's 2014 rate base so that accumulated depreciation reserve and full depreciation expense for 2014 projects are reflected in 2015 rates. Or, as the Department states:

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[9] *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19*, Docket No. E,G-999/M12-587, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTIYEAR RATE PLANS (June 17, 2013) (MYRP Order). The Commission's MYRP Order limited the ability for a utility to request its full cost of service in the out years of an MYRP. Importantly, the MYRP prohibits a utility from updating the O&M portion of its cost of service in the out years of an MYRP, with certain exceptions, and limits requests for capital to "specific, clearly identified capital projects" and "associated non-capital costs." MYRP Order at 1, 4-5, 12.

[10] Order at 25; ALJ Report at 51.

[11] Xcel Energy Initial Brief at 37 (emphasis in original).

> [T]he Department requests that the Commission approve the $17.53 million downward adjustment for the passage of time. The Department would not oppose allowing Xcel to recover annualization of depreciation for any 2014 non-Step project that was not already annualized in the 2015 Step…[12]

Although the Department argues that the record does not disclose the dollars associated with a 2014 non-Step annualization, the record provides the information necessary to perform this calculation.[13] As the ALJ provided in her Report:

> A careful review of the record in this case shows the Department's proposed passage of time adjustment to 2015 Step revenue requirements do not fully account for capital-related effects of the passage of time. The Department's $17.53 million downward adjustment only reflects that change in accumulated depreciation for non-Step projects placed in-service in 2014; it does not reflect the increased expenses due to annualization of depreciation expense or additions to rate base from these same set of projects. When these additional passage of time components are considered, they more than offset the passage of time reductions recommended by the Department.[14]

On reconsideration, the Department continues to question the Company's calculation of an incremental $18.479 million increase of depreciation expense due to the 2014 non-Step projects being annualized into 2015 as an offset to the $17.5 million of annualization of accumulated depreciation for 2014 non-Step projects into 2015.[15] However, the record was sufficiently clear that the ALJ determined:

> In its Reply Brief, the Department questioned whether the $18.48 million increase in depreciation expense calculated by the Company reflects the incremental increase in depreciation expense beyond that already included in the 2015 Step calculation. The Department asserted that the

[12] Department Petition at 12.

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

[14] ALJ Report at 50 (internal citations omitted).

[15] Department Petition at 12.

> amount appears to be the full increase in depreciation expense from 2014 to 2015. The evidence demonstrates, however, that the $18.48 million amount is the incremental increase, not the full amount.[16]

When the Department's calculation is performed by netting the $17.5 million decrease in 2015 rates due to rolling forward the accumulated depreciation of 2014 rate base and the $18.48 million increase in 2015 rates due to annualizing the depreciation expense *for the same set of 2014 projects*, the result is an increase to 2015 rates of $950,000. Due to in part this mathematical outcome, the ALJ correctly determined that:

> Based on the foregoing analysis, the Administrative Law Judge concludes that no downward adjustment to the Company's 2015 Step revenue requirement for the passage of time is necessary. In addition, because the Company has not requested an adjustment for the passage of time, no increase is necessary.[17]

While the Department claims that there is confusion in the record, we believe the ALJ and the Commission understood the issue and reached the correct outcome. To be clear: the $18.48 million calculation of the depreciation expense provided for in Schedule 2, page 5 of the Rebuttal Testimony of Ms. Lisa Perkett represents the annualization of the depreciation expense for only the 2014 plant in-service into 2015 for all projects not included in the 2015 Step. To the extent that the "Department would not oppose allowing Xcel to recover annualization of depreciation for any 2014 non-Step project that was not already annualized in the 2015 Step,"[18] this amount is $18.48 million and, contrary to the Department's assertion, this amount is in the record and is not small.

The record fully supports the Commission's determination with respect to the appropriate application of the Department's proposed passage of time adjustment and there is no need for the Commission to reconsider its decision now.

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[16] ALJ Report at 51(internal citations omitted).

[17] ALJ Report at 51.

[18] Department Petition at 12.

2. Record Development

In light of the Department's Petition request that we provide additional passage of time information in our next rate case filing, the Company has reviewed the record on this issue. While the value was not provided until Rebuttal Testimony, the prosecution of this case and the ALJ's Report demonstrate that the record was fully informed and was sufficiently clear for the ALJ and the Commission to perform the necessary calculations to reach the appropriate conclusion in this case. To the extent that the Department was confused with respect to the Company's calculation of the $18.48 million figure provided in Ms. Perkett's Rebuttal Testimony, it had the opportunity to propound discovery and question Ms. Perkett on the stand to obtain clarity. The Department did neither. That said, we commit to working with the Department to make the value of the passage of time adjustment for both rate base and depreciation expense clear from the outset.

C. Rate of Return (Department)

In its May 28, 2015 Comments on the Company's May 1, 2015 compliance filing related to implementation of the Class Cost of Service Study (CCOSS), the Department briefly suggested that because the Commission did not accept the Department's calculation of the passage of time adjustment, the Commission should not apply the 2015 updated cost of debt to 2014 capital projects carried over to the 2015 Step. We believe that this proposal is not related to the Passage of Time issue as it was recommended by the Department to better reflect our 2015 capital-related financing costs, and we are concerned with the Department making this suggestion now given that the Department maintained a contrary position throughout these proceedings.

The Company further believes that such a proposal would more appropriately have been raised in the Department's request for reconsideration and clarification. Importantly, whether or not to update the cost of debt for rate base from 2014 to 2015 was not brought up on the record because this issue was resolved. Because the Company's Petition for Reconsideration sought clarification of this issue based on an apparent error in the Order, we provide additional information here. Overall, the Company's proposed adjustment is correct, consistent with the Department's recommendations throughout the case, and to the extent the Department attempts to tie it to the passage of time proposal, we believe it is still consistent with that outcome in this proceeding.

For rates to be just and reasonable, the Company must have a reasonable opportunity to earn its authorized rate of return on rate base. Failure to provide the Company with such an opportunity would result in unjust and unreasonable rates. The Department's passage of time adjustment is ultimately related to determining 2015 rate base and the Company's recovery of the capital it has dedicated to the public use.[19] By contrast, the determination as to the proper application of the cost of debt for 2015 is related to the amount that the utility can recover in relation to its costs of obtaining capital to finance its capital investments. Said differently, the Department's passage of time adjustment is used to determine on what capital the Company can earn a return (and recover its capital costs). In contrast, proper application of the cost of debt is critical to providing the Company the necessary opportunity to earn its actual costs of incurring debt and ultimately the Commission's authorized overall rate of return.

Due to this, and consistent with the Department's position prior to its May 28, 2015 Comments,[20] the Company updated its cost of debt for 2015 on the record. Specifically, in direct response to Department witness Dr. Eilon Amit's request in Direct Testimony, we updated the separate costs of debt for 2014 and 2015 in Mr. Tyson's Rebuttal.[21] Dr. Amit subsequently accepted these updated costs of debt, which were incorporated into Department witness Mr. Dale Lusti's Surrebuttal and evidentiary hearing cost of service schedules.[22]

Next, Mr. Lusti's schedules in this proceeding have shown the methodology he used to calculate the Company's 2015 revenue deficiency, and illustrate that he applied the updated cost of capital to the entire 2014 rate base plus 2015 Step.[23] The Company's post-hearing and compliance financial schedules in this proceeding have likewise shown the parties' agreement to apply the updated cost of debt to all capital projects carrying forward from 2014 to 2015, as well as the 2015 Step projects.[24] We respectfully submit that this is the correct methodology.

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[19] The Company recovers its capital expended through the depreciation expense which represents the "consuming" of the capital addition dedicated to the public use.

[20] *E.g.*, Ex. 405, Amit Surrebuttal at 29; Ex. 442, Lusti Surrebuttal at 46-47.

[21] Ex. 31, Tyson Rebuttal at 25-30; Ex. 400, Amit Direct at p. 46-47.

[22] Ex. 403, Amit Surrebuttal at 9-10, 29-30; Ex. 442, Lusti Surrebuttal at Schedule DVL-S-21; Ex. 451, Lusti Opening Statement with Attachments at Schedule DV-EH-21.

[23] Ex. 442, Lusti Surrebuttal at Schedule DVL-S-21; Ex. 451, Lusti Opening Statement with Attachments at Schedule DV-EH-21.

[24] *Issues List* at 16-17 (Oct. 7, 2014); *Xcel Energy Revised Financial and Rate Design Schedules* [to reflect ALJ Report] (Jan. 9, 2015); *Xcel Energy Compliance Filing – Preliminary Schedules* at Schedule A-1 at 2 and 3 (April 24, 2015).

In short, this updated capital-related cost of debt should be applied consistently to all rate base used to calculate our revenue deficiency so that 2015 rates reflect the Commission's authorized rate of return for 2015. This is an actual capital-related cost that should be updated from one year to the next and is consistent with both the Company's and the Department's actions throughout this case.

Applying the updated rate of return to 2014 rate base in 2015 is also consistent with the Department's passage of time concept. Under that proposal, 2014 rate base should be updated due to the passage of time from 2014 to 2015. The ALJ and the Commission agreed with this in concept, but determined that no passage of time adjustment was warranted since a symmetrical application of the concept would result in an increase to 2015 rates that the Company did not request. The ALJ's determination that "[c]onsideration of the effects due to passage of time on rate base and depreciation is necessary to ensure just and reasonable rates"[25] is consistent with applying the updated rate of return in 2015.

Accordingly, the Company respectfully requests that the Commission grant our requested clarification and apply the Commission's authorized 2015 rate of return to all 2015 rate base.

D. Monticello Accounting for Depreciation (Department)

The issue with respect to depreciation for the Monticello LCM/EPU Program is whether the Company should account for depreciation according to standard practice, or should apply depreciation in a new manner the Department proposes on Reconsideration. We respectfully submit that the Company's accounting for Program depreciation satisfies long-standing ratemaking procedures, and is the appropriate way to implement all aspects of the Commission's order in the Monticello prudence investigation.

In its Request for Reconsideration and Clarification, the Department argues that the Company should not account for past depreciation expense and accumulated depreciation for the Monticello LCM/EPU Program in the traditional manner, but rather should assign past depreciation expense and accumulated depreciation from 2009 to 2014 only to the portion of Monticello that will earn a return. The Department suggests that its proposal is necessary to ensure the Company does not earn a return on a greater portion of the asset than the Commission permitted in the prudence proceeding.

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[25] ALJ Report at 50.

We respond with a simple argument that the Commission allowed us a full recovery of our Monticello LCM/EPU Program costs, and that a full "return of" costs, by definition, represents depreciation. When we apply the Commission's order to the Program, which is a multi-year capital project that was placed in service over several years and therefore has been depreciated in staged intervals going back to 2008, our approach is reasonable and consistent with the Commission's policy determinations. We then explain that the Department's approach deviates from standard ratemaking principles by failing to account for the differences between earning a return and recovering depreciation, and would further harm the Company.

By way of background, we obtain a "return of" (*i.e.*, recovery of capital costs) of a project through the depreciation expense that offsets the accumulated depreciation reserve for our capital plant. This represents the "consumption" of the plant through its use to serve our customers. By contrast, we obtain a "return on" our capital investment by applying the Commission's authorized rate of return to our plant in rate base in a given year. The Commission's prudence determination resulted in an outcome where we receive a "return of" all of our capital expended on the Project but a "return on" only the portion equivalent to our escalated initial cost estimate.[26]

At issue here is how the Company should obtain its "return of" capital for the Monticello LCM/EPU Project. In compliance filings, the Company's schedules illustrated a "return of" its capital based on consumption of the asset while it is serving our customers, consistent with how depreciation is normally calculated. More specifically, portions of costs for completed work have been placed in service each year of the Program, beginning in 2008 – but only to the extent permitted by Commission orders regarding what has been "used and useful" each year. Further, the Company has recognized associated depreciation in each year (because the assets developed through the LCM/EPU Program are in fact depreciating over time regardless of collection through rates) and, in certain years, we recorded the depreciation without the ability to collect it from customers. This was consistent with Department witness Ms. Nancy Campbell's testimony that the Company should not be able to recover depreciation expense or a return for amounts – typically pertaining to the EPU – that were not considered "used and useful" in a given year.[27] In other words, the Company did not even earn its full return *of* costs in 2014 (and is not requesting to do so).

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[26] Both the Company and the Department have requested confirmation in the Monticello prudence docket that this is the correct initial cost estimate for the Monticello Program.

[27] Ex. 429, Campbell Direct at 57; Ex. 435, Campbell Surrebuttal at 58.

By accounting for depreciation in the long-accepted manner, we will obtain a "return of" our capital – which is by definition the fixed costs and all depreciation associated with the Program – consistent with traditional ratemaking practices and the Commission's Monticello prudence order allowing us to recover our actual investment in the Program. Our approach further ensures that the plant, the associated depreciation reserve, and ADIT are all in sync with each other.

In contrast, the Department's theory both inequitably penalizes the Company and is inconsistent with the Commission's historic interest in accounting for depreciation consistent with the appropriate percentage of plant in service.[28] The Department proposes that the Company should first recover its capital costs on the portion of the project for which it may obtain a return on investment, and only thereafter begin to recover its capital costs for the portion on which it cannot earn a return. This departs from traditional ratemaking practices by acting as if the entire amount that will not earn a return is being placed in service on January 1, 2015, and then applying past depreciation solely to the initial cost estimate while applying 2015 and future depreciation to the costs that will not earn a return. Because this proposal accounts for accumulated depreciation based on whether Program costs will earn a return, it disconnects the Monticello asset from its associated depreciation.

Perhaps even more importantly, the Department's proposal would result in a duplicate impact to the Company because the Department both fails to account for the depreciation previously applied but not collected from customers (as well as the return on that portion that was not recoverable) *and* now asks the Company to apply prior depreciation solely to the amounts that will earn a return. By treating the entire Program amount that will not earn a return as being placed in service on a single date in 2015, the Department reduces the Company's recovery of Monticello costs in addition to the impact to recovery of past used and useful determinations, the LCM/EPU split determination, and the prudence outcome. This effectively constitutes double counting, and would therefore be unjust and unreasonable.

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[28] In other cases where a party has proposed a mismatch between plant in service and accumulated depreciation, the Commission has found that it is more equitable to keep these components in sync. For example, in Otter Tail Power's 1986 rate case, Otter Tail proposed interim rates allocating a different amount of plant in service to the MN jurisdiction than accumulated depreciation. The Commission determined that this mismatch was inequitable and adjusted the accumulated depreciation to match the percentage of plant in service allocated to the Minnesota jurisdiction. *In the Matter of the Petition of Otter Tail Power Company for Authority to Increase Electric Rates in Minnesota,* Docket No. E-017/GR-86-380, ORDER SETTING INTERIM RATES AT 4-5 (July 18, 1986). In the current proceeding, we propose to keep the plant in service and accumulated depreciation in sync, consistent with this precedent.

Attachment A to this document illustrates that both the Company's and Department's proposals rely on the proportion of the Monticello asset that will not earn a return, consistent with the Commission's order in the prudence investigation. But Attachment A also illustrates that the Department's proposal effectively reduces the amount of capital for which we can earn a "return on" by almost $20 million, and in turn reduces the Company's revenue requirement by a full $2.1 million.

As a final consideration, the Commission's prudence order states that the amount of Monticello Program costs that will not earn a return is a portion of the total Program costs, which were incurred and placed in service over several years. Conversely, the Order does not break down costs that will not earn a return by the year they were incurred or the year placed in service. As such, accounting for depreciation as it is placed in service is not only the accepted ratemaking method, but also is consistent with the Commission's approach in the prudence investigation.

To maintain equity and allow full recovery of the costs of the Program while also implementing the no-return remedy consistent with the Commission's prudence order, previously accumulated depreciation should simply be applied to the Monticello Plant based on traditional ratemaking practices that consider only the timing of dollars in service, as with any other asset. The Company's compliance filings, which illustrate the impact of the Commission's prudence investigation determination, are consistent with this outcome, with Commission precedent, and with the Commission's Order in this proceeding.

E. Prairie Island EPU (OAG)

The OAG's arguments regarding the Prairie Island EPU present no new considerations that warrant reconsideration. The Commission addressed the OAG's arguments regarding both the cost of debt resolution and the recovery of AFUDC. Although on reconsideration the OAG asks that the Commission reconsider allowing the Company to recover its cost of debt for the project and for even greater impact to the Company than the OAG previously requested with respect to AFUDC, the OAG does not provide any thoughts the Commission has not already considered and, in fact, relies heavily on outdated legal support. For these reasons, we ask that the OAG's request be denied.

1. *Recovery of the Cost of Debt*

First, the OAG argues that the Company should not recover the cost of debt for the Prairie Island EPU Project because, in some other circumstances, the costs of a cancelled project have not been allowed any return. In particular, the OAG compares the Prairie Island EPU to IPL's cancelled Sutherland Generating Station, without acknowledging that the lack of a Minnesota Certificate of Need and the relatively small size of the investment for the Interstate Power & Light (IPL) plant were significant factors in the circumstances of cost recovery for that project.[29] Likewise, the OAG compares the Prairie Island EPU to Otter Tail's cancelled Big Stone II project without acknowledging that while Otter Tail did not recover its cost of debt on that project, it was only required to amortize cost recovery over a period of five years.[30] As a compromise based on the outcomes in these most recent cancelled project matters before this Commission, Prairie Island EPU costs are being amortized over 20+ years, with recovery of the cost of debt – and no return on equity (profit) to shareholders.

It is important to recall that the Company's recovery of the cost of debt is a resolution that balances the facts of this proceeding and the Company's prudent investment with the interest of customers, consistent with Commission precedent on this issue. Further, it was the product of other proposals on the record. The Company initially proposed either a 6-year amortization of costs with no return, which would be roughly consistent with the Big Stone II outcome, or 12 years with a return – which would have been a significantly longer amortization period than Big Stone II, but balanced by earning a return on the asset. Either of those outcomes would have been consistent with Commission precedent in the most comparable proceedings. By contrast, the cost of debt recovery over a 20+ year amortization period offers a substantially reduced impact to customers:[31]

Recovery Proposal (dollars in thousands)	**Associated 2014 Revenue Requirement**
6-year amortization, no return	$9,856
12-year amortization with return	$8,562

[29] Indeed, OAG argues that "There are no facts that distinguish the PI EPU from any of these recent decisions" (OAG Petition for Reconsideration at 7), and then ignores the distinguishing factors previously discussed in testimony in this proceeding – namely, the prudence of the Company's investment and process toward raising the issue of potential cancellation, the close question of whether to cancel the project, the existence of a Minnesota Certificate of Need, and the length of the amortization period for recovery of cancelled project costs.

[30] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-10-239, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 12 (Apr. 25, 2011).

[31] The calculations illustrating these amounts, based on the other outcomes of the Commission's Order, are set forth in **Attachment B** to this Response.

12- year amortization, no return	$4,928
***RESOLUTION*: 20+ year amortization, recovery of weighted cost of debt.**	**$3,666**

In arguing against any recovery of the Company's cost of debt, the OAG conflates recovery of the Company's cost of debt – an actual expense – with a "reward" to shareholders. The Company is not seeking a "reward" (the OAG's term[32]) or return *on* the asset on the grounds that we acted prudently; rather, the Company and the Department agreed that it was appropriate for the Company to recover the time value of money for the Project in light of the Company's prudent actions. The Company is not seeking a full rate of return that would include a profit to shareholders. Recovery of the cost of debt is neither a full return on the investment nor a "reward," but rather fundamental recovery of prudently incurred costs.[33]

Next, the OAG cites to a law review article for the proposition that FERC typically does not permit recovery of a *full* rate of return on cancelled projects.[34] In addition to failing to recognize that recovery of the cost of debt is not equivalent to "recovery of a full rate of return," the OAG fails to disclose the conclusion stated in the cited law review article. The article authors do not end the discussion of FERC processes by simply noting that customers pay for the investment and investors do not earn a return; rather, they note in the next sentence that:

> The amortization period [for cancelled projects] is accelerated; typically five years, so as to reduce the carrying charges borne by investors. Finally, FERC has resolved other ratemaking issues, such as the tax consequences and the treatment of AFUDC, in favor of investors.[35]

In short, where FERC does not permit a return, it typically allows a shorter amortization period than will be applied to Prairie Island. As noted above, the Prairie

[32] OAG Petition at 9.

[33] *Northwestern Bell Telephone Co. v. State*, 216 N.W.2d 841, 850 (Minn. 1974); *In re Application of Otter Tail Corp. d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-017/GR-1178, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, at *44 (Aug. 1, 2008), *reh'g granted*, ORDER ON RECONSIDERATION (Oct. 31, 2008) (reconsidered other issues).

[34] OAG Petition for Reconsideration at 7 (quoting Rodney A. Wilson, *Ratemaking Treatment of Abandoned Generating Plant Losses*, 8 Wm. Mitchell L. Rev. 343 (1982)).

[35] Rodney A. Wilson, *Ratemaking Treatment of Abandoned Generating Plant Losses*, 8 Wm. Mitchell L. Rev. 343, 351–52 (1982).

Island EPU amortization is nearly four times the length of typical FERC amortization periods, thereby further supporting recovery of the cost of debt in conjunction with a 20+ year amortization period.

Further, while the OAG selectively cites portions of Commission orders and law review articles to support its position, it neglects to cite sources that argue for a full return on prudent investments in projects that are subsequently cancelled:

> [I]f the decisions to build the plant, to continue the planning and construction of the plant and, finally, to cancel the plant were all prudent, then the costs associated with the cancelled construction project should be recoverable from the utility's customers over a reasonable period of time. During the period when these costs are being recovered, investors should be allowed a return on their unrecovered investment. Any ratemaking treatment short of this full recovery by investors penalizes utility investors and, ultimately, discourages utilities from undertaking costly, risky projects for new plant construction that are necessary to meet the nation's energy requirements.

As noted, the Company is not seeking a full return.

The OAG also argues that in the Commission's 1987 decision regarding the Spiritwood cancelled project, the Commission noted that the risk of cancelling projects was incorporated into the overall rate of return for shareholders. However, the Commission also noted that the method of recovering cancelled project costs is a fact-intensive inquiry, dependent on the circumstances of each case and an assessment of what will be just and reasonable.[36] As discussed further below, the Company's prudence with respect to the Prairie Island EPU underscores the appropriate recovery of the cost of debt coupled with an extended amortization period.

2. AFUDC

The OAG also argues that the Commission should reconsider its decision allowing the Company to recover approximately $12.8 million in AFUDC for the Prairie Island

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[36] *In the Matter of the Petition of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-017/GR-86-380, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 7 (Apr. 27, 1987).

EPU project as inconsistent with the Uniform System of Accounts (USoA). The OAG makes two alternative arguments. First, the OAG argues that the Company should not be allowed to recover *any* AFUDC for the project (a new argument) under the USoA because the project was "ultimately" abandoned. Second, the OAG argues in the alternative that the Company should not recover AFUDC for the period after which the OAG claims the Company cancelled the Program in 2011.

We are concerned that the OAG's arguments mischaracterize both the USoA requirements and the record with respect to the timing and extent of the Company's re-evaluation and ultimately cancellation of the Prairie Island EPU project. A more accurate review of applicable precedent and proceeding record illustrates that the Commission reached a reasonable conclusion regarding Prairie Island EPU AFUDC.

First, the OAG incorrectly claims that the USoA prohibits the Company from recovering any AFUDC for a cancelled project. However, the express language of the USoA provides that "[n]o allowance for funds used during construction charges shall be included in these accounts *upon expenditures for construction projects which have been abandoned*."[37] As Company witness Ms. Lisa H. Perkett described on the record, this provision means that "FERC rules prevent accruing *additional* AFUDC on expenditures made during project suspensions and after project terminations."[38] The Company complied with this requirement, and only accrued AFUDC at the appropriate time. Indeed, the Company's approach was thoroughly reviewed in testimony, approved by the Company's independent auditors, vetted by the ALJ, and appropriately decided by the Commission based on the supported facts in the record.

The OAG also makes the argument that "there is a significant body of law holding that AFUDC should be disallowed when a utility construction project is cancelled." However, the precedent the OAG cites is both outdated – as noted by the Commission in the very IPL case OAG cites – and specifically distinguishable on its facts.

The precedent the OAG cites regarding AFUDC recovery on cancelled projects is largely from the 1980s. In particular, the OAG focuses on a 1988 IPL decision by this Commission addressing, among other things, whether AFUDC could be applied to several cancelled projects. While the OAG is correct that at that time there was some focus on whether plant was "used and useful," this Commission has more recently been clear in both the current rate case and several prior cases (including a

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[37] FERC USoA, 18 C.F.R. § 101, Electric Plant Instruction 3(17) (emphasis added).

[38] Ex. 94, Perkett Rebuttal at 32.

2011 decision with respect to a more recently cancelled IPL project), that "there is no public interest or regulatory benefit to be gained by disallowing costs prudently incurred in good faith to meet future need…"[39] Further, FERC has likewise been clear that "it must be reemphasized 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."[40] Thus the "used and useful" argument is far less relevant to cancelled projects than the prudent investment standard.

In addition, it is well settled in these cases that while utilities must utilize the USoA, it is not determinative of ratemaking for AFUDC. The Commission indeed noted in the 1988 IPL case that *utility accounting* practices must conform with the USoA (assuming the USoA stated what the OAG contends), but also stated that a rate-setting body need not base its decisions solely on utility accounting practices. In *Interstate*, the Commission specifically noted that "First of all, it is important to state that the classification 'AFUDC' (Allowance for Funds Used During Construction), which includes interest, carries with it considered policy judgments about how expenses which are so designated should be treated."[41] The Commission then goes on to discuss how AFUDC rate recovery has evolved even as USoA accounting requirements for utilities have not, and how AFUDC recovery frequently depends on the facts of the case.[42]

Moreover, the 1988 Commission decision cited by the OAG is, on its face, specific to the facts of that case. There, the Commission said:

> On the particular facts of this case, the Commission has determined that interest is not recoverable. It is not recoverable as to the Carroll County projects for the same reasons that legal, administrative, and land acquisition costs are not recoverable – that project never left the nascent stage and these costs were prematurely and imprudently incurred. It is not recoverable as to the White-Eldorado

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[39] *In re 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).

[40] III FERC REP. (CCH) T 30,455, at 30,507 (May 16, 1983).

[41] *In the Matter of the Application of Interstate Power Company for Authority to Increase its Rates for Electric Service in Minnesota*, Docket No. E-001/GR-86-384, ORDER AFTER REMAND at 5 (July 5, 1988) ("1988 Interstate Order").

[42] 1988 Interstate Order at 5-6.

> transmission project for a related reason. This project never progressed beyond the planning stage.[43]

The facts of the Prairie Island EPU are quite different, as the Company was nearing completion of the initial NRC license amendment request process when re-evaluation of the project became necessary. The prudence of our actions is well documented in the record, and discussed appropriately in the Commission's Order. In fact, the OAG does not challenge the prudence of the Company's actions on reconsideration; it simply asks the Commission to reconsider its judgment of the appropriate outcome. Under these circumstances, reconsideration is not warranted.

In the alternative, the OAG argues that the Company should not recover all or a portion of AFUDC because the Company should have or did suspend the Prairie Island EPU project in 2011. These are not new arguments – they were raised and discussed extensively before both the ALJ and Commission, and need not be reconsidered. We highlight our position simply to be clear that this issue was thoroughly assessed and that the OAG's arguments do not support a different outcome.

In arguing that the Company fully suspended or cancelled the Prairie Island EPU project more than a year before it had a Commission Order terminating the project prospectively, the OAG misrepresents the record. For example, the OAG states the following in its Request for Reconsideration:

> In his opening statement, Mr. McCall testified that the Company suspended the Project in 2011:
>
> "Based on the culmination of these concerns and because we were not yet in the implementation phase for the Prairie Island EPU project, we were largely able to suspend the project by the end of 2011."[44]

It should not be necessary to clarify that there is a material difference between fully suspending work on the project, as OAG argues, and being "largely able to suspend the project." There is no dispute that the Company began to ramp down the project in late 2011, based on a prudent assessment of the prospects for project success. But the Company's careful management and continuing assessment of the project during

[43] 1988 Interstate Order at 6.

[44] OAG Petition for Reconsideration at 18 (quoting Tr., Vol. 1, at 201:10–14 (Aug. 11, 2014) (McCall)).

2011 and 2012 demonstrate that the Company was appropriately managing the Prairie Island EPU project and ramping down over time consistent with the circumstances we faced.

The evolving circumstances surrounding Prairie Island in 2011 and 2012 are part of robust discussion in the testimony of Company witnesses Mr. Scott McCall and Mr. James Alders. Among other things, Mr. McCall explains in detail how the NRC provided information that the licensing process would be longer and more complex than the Company could have known, but also details the Company's thorough analysis of these changes as information evolved.[45] Thus it is not correct, as the OAG asserts without support, that the Company essentially cancelled the project following the NRC meeting in August 2011 or that the Company had already concluded the project was no longer viable.

Rather, the Company took the additional information from the NRC, "assessed the likely cost of the required additional design efforts," and reasonably estimated the additional cost requirements.[46] Such estimates take time to develop internally and with vendors, and in any event were only one part of the Company's overall assessment. It is critical to note that this information did not lead to a conclusion that the Project was no longer viable. Rather, throughout 2011 and the first three quarters of 2012 the Company's and Department's models continued to illustrate net benefits for the Project.[47] And as the Commission noted in its recent Order, the Company gave notice of its concerns within approximately two months of the NRC meeting, gave an update in our December Resource Plan update, and presented a robust Notice of Changed Circumstances shortly afterward.

In addition, while the Company largely suspended its internal work, Westinghouse was completing its contractual work for the Company in 2012. Westinghouse was the Company's key contractor for the work necessary to obtain the NRC license amendments for the Prairie Island EPU project.[48] We worked closely with Westinghouse and, at the beginning of the project, developed a milestone based contract pursuant to which Westinghouse would receive guaranteed lump sum payments upon achieving certain project milestones.[49] If the Company terminated the contract without any fault to Westinghouse before a specific milestone was reached,

[45] Ex. 49, McCall Direct at 28-31.
[46] Ex. 49, McCall Direct at 30-31.
[47] Ex. 48, Alders Direct at 13-18.
[48] Ex. 49, McCall Direct at 12-13.
[49] Ex. 49, McCall Direct at 18-19.

then the Company would have to pay termination charges to Westinghouse.[50] This contract structure reflects industry standards and "protects the Company and our customers in most instances, as it allows us to reserve material cash outlays to a vendor until we are assured the work is substantially complete."[51]

When it became apparent near the end of 2011 that there was a potential to cancel the project, the Company was faced with a decision of whether to terminate the Westinghouse contract and pay the termination penalties or allow Westinghouse to complete its work. "[B]ecause our cost-benefit analysis of the overall Project did not clearly point to cancellation, we determined that it was better to receive the deliverables while our Change in Circumstances filing was considered, rather than terminate the Westinghouse contract prematurely."[52] This decision weighed the costs of termination penalties against the value of the work we would receive from Westinghouse due to the uncertainty of moving forward with the project. The analysis provided by Westinghouse "would be critical to our [license amendment request] application if the Project proceeded."[53] Thus, we prudently continued the project into 2012 with Westinghouse, based on our assessment that doing so was in customers' best interest. The OAG does not address any of these facts Mr. McCall and Mr. Alders discussed in the record.

In addition, the OAG ignores that at every stage of the Company's review of the prudence of continuing the Prairie Island EPU project, the overall cost/benefit analysis showed a positive present value of revenue requirement (PVRR) for the project.[54] In fact, based on the facts available as late as May of 2012, the Department still recommended moving forward with the project:

> In response to the Notice of Changed Circumstances, the Department of Commerce Division of Energy Resources (Department) provided comments on the Company's analysis. Upon initial review, the Department stated that preliminary results showed the EPU Project was cost

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[50] Ex. 49, McCall Direct at 19.

[51] Ex. 49, McCall Direct at 34-35.

[52] Ex. 49, McCall Direct at 35.

[53] Ex. 49, McCall Direct at 36.

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

> effective despite delays in timing and updated assumptions.[55]

It was only a few months later that the Department determined it was appropriate to cancel the project, and the project was terminated prospectively by Commission Order in February of 2013.[56]

In light of these prudent considerations and the most recent policy decisions of the Commission with respect to cancelled project cost recovery, we continue to believe the outcome adopted by the Commission presents an appropriate balancing of interests presented by a lengthy amortization period coupled with recovery of AFUDC and the Company's cost of debt. As such, no reconsideration is needed.

F. Nuclear Refueling Outage Amortization (OAG)

The OAG's arguments regarding nuclear refueling cost recovery and carrying charges likewise present no new issues that warrant reconsideration. The OAG again claims that not adjusting 2015 rates to remove this expense is inconsistent with the Commission's multiyear rate plan order (MYRP Order) and that the Commission has not fully justified why there should be no adjustment for nuclear refueling outage expenses. The OAG also argues, as it has argued throughout this proceeding and argued unsuccessfully in multiple past Company rate cases,[57] that the Company should not earn its full rate of return on the deferred nuclear refueling outage costs.

The OAG's arguments were the subject of detailed testimony and were fully vetted in these proceedings. Subsequently, both the ALJ and the Commission appropriately determined that the long-standing approach to nuclear refueling outage costs was not only *consistent with* the MYRP Order but also *required by* the order's limitation on updating non-capital costs. Indeed, the language in this rate case Order stating that: "Consideration of the full spectrum of increasing and decreasing non-capital costs in a step year would undermine the efficiency purpose of multiyear rate-setting — to do so would effectively require a full rate case for each year of the plan"[58] is fully in line

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[55] Ex. 48, Alders Direct at 19 (citations omitted).

[56] Ex. 48, Alders Direct at 19.

[57] *See. e.g.*, Ex. 370, Lindell Rebuttal at 6; OAG Initial Brief at 28-29; *In re Application of Northern States Power Company, d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-12-961, Lindell Direct Testimony at 32 (Feb. 28, 2013); *In re Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-10-971, Lindell Surrebuttal Testimony at 17-18 (May 26, 2011).

[58] Order at 28.

with very similar language in the MYRP Order.[59] It further is ample explanation for the Commission's decision. Finally, the OAG's argument regarding the carrying charge on deferred nuclear refueling outage costs has likewise been fully vetted by the Commission. The Company amortizes recovery of these costs for the benefit of customers, warranting a carrying charge due to the otherwise lost time value of money.

G. Sherco 3 Insurance Proceeds (OAG and Department)

Given the myriad comments received on various compliance filings the Company has made in this case, and the new issues raised by the Parties on compliance, the Company takes this opportunity to provide a response to the OAG and the Department's Comments related to our treatment of the capital costs of the Restoration Project at Sherco Unit 3. Importantly, both the Department and the OAG note information provided to the Parties in response to Information Requests when providing their Comments and the Company believes there is a need to inform the record to clarify this information.

At the outset, we note that our proposed treatment of the larger than expected insurance reimbursement is consistent with our commitments with respect to insurance recovery of the Sherco 3 Restoration Project as well as the operation of the Capital True-Up agreed to by the Department and adopted by the Commission in this case. In our initial Compliance Filing, our calculation of the Capital True-Up amounts related to Sherco 3 simply applied traditional ratemaking methods to the capital expended and the insurance recovery received for Sherco 3. In response to the OAG's discovery, we recognized the timing impacts of the larger than expected insurance recovery for Sherco 3 by including 2015 insurance recovery amounts in our calculation of the 2014 true-up. However, because our capital expenditures in 2013 were larger than forecasted in our initial case, the 2014 revenue requirement for Sherco 3 is larger than forecasted notwithstanding the larger than expected insurance recovery. The Comments of the OAG and the Department reflect frustration with the effects of the rate setting process on the capital costs of Sherco 3, net of all insurance proceeds, and nothing more.

Consistent with past practice, we recognized capital expenditures for the Sherco 3 Restoration Project in the month they were made and then recognized the insurance reimbursements when they were received. As noted in the Direct Testimony of Company Witness Mr. Ronald Brevig, we worked cooperatively with our insurers to

[59] MYRP Order at 10.

develop a mechanism under which our insurers would help cash flow our restoration activities. This cooperative relationship resulted in a much closer in time recognition of insurance reimbursements to when we expended funds to restore Sherco 3. By better matching the timing of insurance reimbursements to our actual work, we were able to significantly reduce Sherco 3 rate base amounts while restoration work was ongoing, thereby benefitting our customers.

That said, in an effort to restore Unit 3 to service as quickly as possible, the Company had expended more capital in 2013 than originally forecasted and then originally cash flowed by our insurers. This led to a larger beginning of year balance when calculating 2014 rate base and associated 2014 depreciation expense for Sherco 3 than originally forecasted. This accelerated spending was higher than our larger than expected insurance reimbursement for the Sherco 3 Restoration. Consequently, our 2014 revenue requirement was higher than initially forecasted, even when all 2014 and 2015 insurance reimbursements are accounted for in this calculation.

This result is due to accelerated spending in 2013 on Sherco 3 Restoration work and the timing of our actual insurance reimbursements. To be clear, we have provided in discovery the full insurance reimbursement (those received in both 2014 and 2015) in our 2014 revenue requirement calculation, consistent with our commitments. However due to the Commission's established beginning of year/end of year plant balance averaging method to calculate rate base in a test year, the accelerated 2013 expenditures result in a higher 2014 beginning of year balance against which we calculated rate base and associated revenue requirements (including depreciation expense). In other words, we determined 2014 revenue requirements for our Sherco 3 work in the same manner we would for any other capital project and obtained a slightly higher result even when recognizing additional, larger than expected, 2015 insurance reimbursement in 2014.

The OAG and Department in essence argue for a departure from established rate making practices and would require the Company to recognize all insurance proceeds, no matter when received, in 2013, a period outside of the test year. However, this would not recognize the Company's actual costs of the Restoration Project. We believe this to be inconsistent with the Department's "overall goal … to treat the insurance proceeds in the same manner as the recovery of capital costs."

The 2014 Capital True-Up mechanism adopted by the Commission, and uncontested by the OAG until Commission deliberations on this rate case, is on a revenue requirements basis. This means that the Company calculates the true-up based on the revenue requirements for its capital projects and not on a capital additions basis. We merely applied standard ratemaking techniques to the calculation of the Sherco 3 revenue requirement and achieved the outcome objected to by the Department and the OAG. Because the 2014 revenue requirement for Sherco 3 was higher than anticipated due to accelerated capital expenditures to bring the Unit back in service as quickly as possible, the 2014 Capital True-Up mechanism reflects a slightly higher 2014 revenue requirement for our Sherco 3 restoration efforts even when all insurance reimbursements are accounted for regardless of when they were received. Accepting the Department and OAG's comments would lead to a significant departure in standard ratemaking practices. That said, we note that the 2014 Capital True-Up is applicable to all 2014 capital additions and as a 2014 capital addition, our Sherco 3 Restoration Project would have been included in the Capital True-Up regardless of our ultimate insurance recovery.

We recognize that the revenue requirements outcome for 2014 related to Sherco 3 is counterintuitive. However, as noted, it is merely the product of established ratemaking practices. That said, the revenue requirement impact of this result (approximately $344,000 or $311,000 when 2015 insurance proceeds are accelerated into 2015) has no material impact to 2014 revenue requirements in this case since our total true-up amount was approximately $6.8 million above the Commission's authorized capital related revenue requirement, thereby resulting in no adjustment. Additionally, now that all insurance proceeds have been received, we will reflect the actual cost of the Sherco 3 Restoration, net of all insurance proceeds, in the beginning plant balance of our upcoming rate case, thereby ensuring our customers only pay for the costs of Sherco 3 not reimbursed by our insurers.

CONCLUSION

The Company respectfully requests that the Commission deny the Department and OAG's Petitions for Reconsideration and new revenue-related compliance proposals addressed above. The Company believes the Commission's Order represents a reasonable outcome in this proceeding and that the resulting rates will be just and reasonable upon adoption of the Company's May 28, 2015 Petition for Limited Reconsideration and Clarification.

Respectfully submitted,

Northern States Power Company

June 8, 2015

Amounts in $000s

		DOC Method		Company Method		Company Request for Reconsideration	
		Assign Dep'n to Portion Earning Return Only No Return in 2015 on $333m		Standard Ratemaking No Return in 2015 on $333m		Standard Ratemaking Weighted Debt Return in 2015 on $333m	
			73.9969%		73.9969%		73.9969%
		Adjusted	After I/A	Adjusted	After I/A	Adjusted	After I/A
	Rate Analysis	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur
1	Plant Investment	(320,404)	(237,089)	(320,404)	(237,089)	(320,404)	(237,089)
2	RWIP	(12,596)	(9,321)	(12,596)	(9,321)	(12,596)	(9,321)
3	Plant plus RWIP	(333,000)	(246,410)	(333,000)	(246,410)	(333,000)	(246,410)
4	Depreciation Reserve w/o RWIP	(10,571)	(7,823)	(51,290)	(37,953)	(51,290)	(37,953)
5	CWIP	-	-	-	-	-	-
6	Accumulated Deferred Taxes	(75,377)	(55,777)	(60,534)	(44,793)	(60,534)	(44,793)
7		(247,051)	(182,810)	(221,176)	(163,663)	(221,176)	(163,663)
8							
9	Average Rate Base	(247,051)	(182,810)	(221,176)	(163,663)	(221,176)	(163,663)
10							
11	Debt Return	(5,608)	(4,150)	(5,021)	(3,715)	-	-
12	Equity Return	(12,600)	(9,323)	(11,280)	(8,347)	(11,280)	(8,347)
13	Current Income Tax Requirement	(8,890)	(6,579)	(7,959)	(5,890)	(7,959)	(5,890)
14							
15							
16	Book Depreciation	-	-	-	-	-	-
17	Annual Deferred Tax	-	-	-	-	-	-
18	ITC Flow Thru	-	-	-	-	-	-
19	Tax Depr & Removal Expense	-	-	-	-	-	-
20	AFUDC Expenditure	-	-	-	-	-	-
21	Avoided Tax Interest	-	-	-	-	-	-
22	Total Revenue Requirement Adjustment	(27,098)	(20,052)	(24,260)	(17,952)	(19,239)	(14,236)

At Newly Authorized

Capital Structure	**Rate**	**Ratio**	**Weighted Cost**
Long Term Debt	**4.9400%**	**45.6100%**	**2.2500%**
Short Term Debt	**1.1200%**	**1.8900%**	**0.0200%**
Preferred Stock	**0.0000%**	**0.0000%**	**0.0000%**
Common Equity	**9.7200%**	**52.5000%**	**5.1000%**
Required Rate of Return			**7.3700%**
PT Rate			
Tax Rate (MN)	**41.3700%**		

Northern States Power Company
Prairie Island EPU Amortization
Alternative Recovery Scenarios
2014 Revenue Requirements

Docket No. E002/GR-13-868
Response to Petitions for Reconsideration
Attachment B

	Amounts in $000s	A	B	C	D	E	F	G	H	I	J	K	L
		Final Rate Case Order				6 Year No Return				12 Year Full Return and No Return			
		Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur	Total Co	MN Jur
		Full Project		Equity Return		Full Project		Debt & Equity Return		Full Project		Debt & Equity Return	
		2014	**2014**	**2014**	**2014**	**2014**	**2014**	**2014**	**2014**	**2014**	**2014**	**2014**	**2014**
1	Plant Investment	78,885	58,643	78,885	58,643	78,885	58,643	78,885	58,643	78,885	58,643	78,885	58,643
2	Depreciation Reserve	1,940	1,442	1,940	1,442	6,574	4,887	6,574	4,887	3,287	2,443	3,287	2,443
3	CWIP	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	31,455	23,384	31,455	23,384	29,561	21,975	29,561	21,975	30,904	22,974	30,904	22,974
5	Total Rate Base	45,490	33,817	45,490	33,817	42,750	31,781	42,750	31,781	44,694	33,225	44,694	33,225
6		-	-	-	-	-	-	-	-	-	-	-	-
7	Average Rate Base	45,490	33,817	45,490	33,817	42,750	31,781	42,750	31,781	44,694	33,225	44,694	33,225
8		-	-	-	-	-	-	-	-	-	-	-	-
9	Tax Preferenced Items:	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-
11	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-	-	-	-	-
13	Debt Return	1,019	758	-	-	958	712	958	712	1,001	744	1,001	744
14	Equity Return	2,320	1,725	2,320	1,725	2,180	1,621	2,180	1,621	2,279	1,694	2,279	1,694
15	Current Income Tax Requirement	3,255	2,420	1,637	1,217	7,023	5,221	1,538	1,144	4,351	3,234	1,608	1,196
16		-	-	-	-	-	-	-	-	-	-	-	-
17	Book Depreciation	3,880	2,884	-	-	13,147	9,774	-	-	6,574	4,887	-	-
18	Annual Deferred Tax	(1,586)	(1,179)	-	-	(5,375)	(3,996)	-	-	(2,687)	(1,998)	-	-
19	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-
20	Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-
21	Total Revenue Requirements	8,888	6,607	3,957	2,942	17,934	13,332	4,676	3,476	11,518	8,562	4,889	3,634
22													
23	Net Revenue Requirement	20.3 Year Debt Return		4,931	3,666	6 Year No return		13,257	9,856	12 Year No Return		6,629	4,928
				= A - C	= B - D			= E - G	= F - H			= I - K	= J - L