Minnesota Public Utilities Commission

Staff Briefing Papers
Volume VII - Financial

Meeting Date: March 19, 2015 Oral Arguments .... Agenda Item # _____

March 26, 2015 Deliberations

Company: Northern States Power Company d/b/a Xcel Energy

Docket No. E-002/GR-13-868

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

Issue(s):
Prairie Island EPU 2014
Babcock & Wilcox Nuclear Energy, Inc. Lawsuit
Nuclear Refueling Outage Cost Amortization
MYRP Rate Moderation Proposal – DOR Settlement Funds (Step)
CWIP/AFUDC
Return on Nuclear Refueling Outage Costs
Nuclear Theoretical Depreciation Reserve
MYRP in General
Rate Moderation Proposal – TDG Theoretical Depreciation Reserve Surplus
Depreciation and Plant Retirements in the 2015 Step – Passage of Time (2015 Step)
Changes to In-Service Dates for Capital Projects (2014 and 2015 Step)
Xcel's Interim Rate Proposal
Interest Rate on Interim Rates Refund
Fuel Cost Recovery Reform
Sherco 3 Outage – Replacement Fuel Costs
Black Dog Units 2 and 5 Outage Costs

Staff:
Jerry Dasinger .... (651) 201-2235
Jorge Alonso... (651) 201-2258

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless otherwise noted.

This document can be made available in alternative formats (e.g., large print or audio) by calling 651-296-0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service.

Table of Contents

Prairie Island EPU (2014)

PUC Staff: Jerry Dasinger

Xcel

Clark Direct pp. 30- 41
Clark Rebuttal pp. 48-59
Alders Direct pp. 8-22
McCall Direct pp. 12-39
Perkett Rebuttal pp. 31-36
Weatherby Direct pp. 5-28
Weatherby Rebuttal pp. 1-9

The Company[1] stated it is seeking recovery of $66.1 million, which is the total amount of its expenditures to carry out the Project, plus accrued AFUDC of $12.8 million. It proposed to amortize cost recovery over 12 years while earning a return on the asset, or six years if no return is permitted.

Summary of Prairie Island EPU Costs by Category[2]

EPU Cost Category	**Final EPU Costs** ($ in millions)
Vendor Costs:	
EPU studies, LAR and Certificate of Need	$ 48.2
Engineering Analysis & Licensing Support for LAR Inputs	6.8
Engineering - owner's acceptance	5.4
Project Management & Administrative Support	0.9
EPU Equipment Costs	0.3
Other (vendors under $50,000 each over all years)	0.4
Internal Costs:	
Employee Labor, Benefits & Expenses (mainly project management and engineering)	3.3
Overheads Charged to Project	0.8
TOTAL EPU COSTS (excluding AFUDC)	**$ 66.1**

[1] Clark Direct p. 31
[2] Weatherby Direct p. 23

According to the Company,[3] the appropriate standard of review to apply to the Prairie Island cancelled Project is the prudence standard. This standard requires the Commission to determine whether the Company's actions fell within a range of reasonableness in light of the circumstances with which it was confronted at the time of its decisions. This standard is not simply a determination of one party's opinion or preference for a different set of circumstances, but rather requires a factual inquiry. Finally, the prudence standard does not rely on hindsight to evaluate a decision.

In recent years, several cancelled projects[4] have been brought to the Commission for review and examination of requests for cost recovery. The Company stated that in these cases, the Commission has focused on the reasonableness of the utility's decisions and of the costs incurred during the project's active and wind-down phases.

Xcel[5] argued that if the appropriate standard for cost recovery of cancelled project costs was whether the project is "used and useful," by definition no project that was cancelled before it was placed in service could be eligible for cost recovery. This would defeat the Commission's public policy to encourage a utility's diligence in "promptly withdrawing from projects when experience shows that they will no longer serve ratepayers' best interests."

The Company also argued that it is likely that the Prairie Island project would have satisfied the deferred accounting standard if the company had requested deferred accounting. The Company further argued that the costs are: 1) related to utility operations for which ratepayers have incurred costs or received benefits; 2) Significant in amount; 3) Unusual or extraordinary items; and 4) Subject to review for reasonableness and prudence. Ultimately, it believed the Commission would have allowed deferred accounting of these costs as a matter of public policy considerations.[6]

According to the Company, once it became clear from the Commission meeting held in December 2012 that the Prairie Island EPU was unlikely to continue, the Company transferred $66.1 million of Project expenditures as well as cumulative AFUDC of $8.3 million in AFUDC-equity and $4.5 million in AFUDC-debt, for a total of $78.9 million of incurred costs, to a regulatory asset. Xcel stated that its review of Generally Accepted Accounting Principles indicated it was appropriate to create a regulatory asset for financial recordkeeping purposes for the Prairie Island project costs

The Company provided the following explanation as to why it recorded the EPU costs as a regulatory asset:

---

[3] Clark Direct p. 32
[4] Interstate Power & Light's (IPL) cancelled Sutherland Generation Station Unit 4 project (SGS Unit 4) in Docket No. E-001/GR-10-276, and Otter Tail Power's cancelled Big Stone II transmission project in Docket No. E-017/GR-10-239
[5] Clark Direct p. 34
[6] Clark Direct pp. 38-40

> We recognize this is not a ratemaking issue but rather is a question of the Company's compliance with applicable accounting requirements. The Company's Controller, in consultation with the Company's external independent auditors, determined that such accounting was appropriate under generally accepted accounting principles (GAAP) and FERC accounting regulations. The following is my understanding of the Company's assessment. Under Financial Accounting Standards Board (FASB) Statement No. 90 and FERC regulations 18 CFR Ch. 1 for Account 182.3 – Other Regulatory Assets, it is appropriate for the Company to move abandoned plant costs to a regulatory asset if the Company reasonably believes the Commission will allow recovery of the costs. In this case, once it became evident that the Commission was going to approve termination of the Project, the Company assessed past Commission precedent regarding abandoned or cancelled projects and applied those assessments to its own activities at Prairie Island. Based on that assessment, the Company, in consultation with its independent auditors (regarding accounting requirements) and legal counsel (regarding regulatory precedent), concluded it was appropriate to move the previously capitalized costs from plant CWIP accounts to a regulatory asset account.[7]

Xcel stated that although it believes that all costs associated with the Prairie Island EPU were prudently and reasonably incurred, according to GAAP, regulatory assets associated with an abandonment cannot be recorded at their full amount of capitalized cost unless it is considered probable that the costs will both (a) be fully recoverable in rates and (b) earn a return in the ratemaking process. The Company argued that these costs are entitled to a return through a carrying charge on unrecovered amounts. However, considering past Commission precedent on other abandoned projects within its jurisdiction there is some uncertainty as to whether such a return will be approved in this rate case. Recognizing this uncertainty, GAAP requires that the Company record the costs on a discounted cash flow basis in its financial statements using a hypothetical debt discount rate over the 12-year amortization period requested by the Company. This accounting resulted in the Company taking a $10.1 million pretax charge in December 2012 to record the regulatory asset on a discounted basis.

The Company argued that this does not mean that the company has permanently written off the $10.1 million. These costs were recorded on the assumption that all costs would be recovered but a return was not assured. If the Commission approves its request to recover the Prairie Island EPU costs with a return, it would reverse the 2012 charge of $10.1 million consistent with GAAP standards. If the Commission does not approve a return, then the pretax charge will be amortized back into regulatory assets each year through a process called accretion. This effectively "undiscounts" the costs over time and still recognizes the total incurred costs over the regulatory amortization period.

[7] Weatherby Direct pp. 25–26

Xcel[8] stated Mr. Lindell's recommendation to disallow recovery of the $10.1 million inappropriately double-counts the $10.1 million charge. If the Company was prohibited from both earning a return on the incurred costs and recovering capitalized project costs equal to the $10.1 million pretax charge, GAAP would require the Company to recognize an impairment charge for a direct disallowance of $10.1 million of incurred costs, in addition to the GAAP pre-tax charge already recognized to present the full amount of incurred costs on a discounted basis.

Xcel[9] proposed to amortize the costs of the Project over twelve years with a return on its investment. The Company argued that the request for a return on its investment reflects the unique circumstances of the Prairie Island EPU. It devoted substantial resources to the program over a number of years, in an effort to provide its customers with additional clean, reliable baseload energy at a time when EPU projects were favored and its load forecast showed a substantial need.

In rebuttal, Xcel[10] stated although it continues to believe its initial recommendation was reasonable in light of both Commission precedent and the Company's prudent management of the Prairie Island EPU project, it would like to offer a reasonable compromise. The Company suggested amortizing the Project costs over a 12-year period without a return on the investment. The Company stated it believes this is a reasonable compromise because the Parties' proposals reach a harsher result than the Commission has previously imposed on a utility seeking to recover the costs of a cancelled project. The Commission has historically implemented an amortization period of less than the life of the project without a return on the asset for recovery.[11] If the Commission believes the costs of this Project should be recovered over the life of the Project, then Xcel proposed to amortize the costs with a debt return on the asset.[12]

Xcel[13] stated it disagreed for three reasons with the ICI suggestion that by allowing cost recovery of cancelled projects the commission would encourage "imprudent" or "marginal" project spending because a utility could always recover the cancelled project's costs. First, the Company supports the same prudency standard the Commission has adopted with respect to prior cancelled projects. Because this standard requires the utility to establish that a project was undertaken in a prudent manner, by definition the Commission would not be encouraging utilities to undertake imprudent or marginal projects. Second, the existence of a CON for the Prairie Island EPU project not only underscores the prudence of undertaking the project based on the circumstances known at the time, but also required the Company to undertake the project once the CON was granted. Third, the ability to recover costs of a project that is cancelled in a prudent manner serves to encourage utilities to make difficult decisions once projects are already underway.

[8] Weatherby Surrebuttal pp. 5-11
[9] Clark Direct p. 41
[10] Clark Rebuttal pp. 50-51
[11] This sentence reflects the correction from the July 25, 2014 Errata filing. The sentence originally ended with the following: or used the time period of the life of the project with a return on the asset. The recovery approved for IPL was over the life of the asset <u>without</u> a return.
[12] The debt return would be 4.76 percent as stated in Heuer Rebuttal p. 17
[13] Clark Rebuttal pp. 53-54

In response to the OAG allegation that the Company might have been able to cancel the project earlier and save additional costs, Xcel[14] stated that it couldn't have prudently cancelled the Prairie Island EPU earlier. Circumstances affecting the Prairie Island EPU were evolving throughout 2011, including the potential scope changes identified in early 2011, delays in receiving its NRC operating license extension, its 2011 experience with the Monticello outage, its summer 2011 meeting with the NRC regarding the timing of uprate licensing, and completion of its additional resource planning and Prairie Island EPU licensing assessments in late 2011.

At the time the Company filed its Petition and Notice of Changed Circumstances, all work on the Project had been suspended except for the remaining deliverables of the Westinghouse contract. The Company had determined that due to the termination provisions of the Westinghouse contract, it was better to receive the deliverables of the contract by summer of 2012 as contracted than pay similar contractual termination fees and receive no product.

The OAG recommended disallowance of AFUDC costs of $12.8 million. The Company[15] stated that FERC rules provide that additional AFUDC is not available for expenditures made on abandoned projects. However, it does not support the write off of AFUDC taken up to the time of abandonment. The investment costs accumulated during active construction existing at the time of the cancellation are recoverable for the entire period during which the project remained prudent.

In his Opening statement, Mr. Clark stated: I am further able to confirm the Company will accept Mr. Lusti's alternative Surrebuttal proposal to amortize the total Prairie Island EPU costs over the remaining life of the facility, with Mr. Lusti's revised debt return on the asset.

Department of Commerce

Lusti Direct pp. 15- l 8
Lusti Surrebuttal pp. 3-7

The Department stated the Commission allowed recovery of cancelled project costs in the recent IPL (E-001/GR-10-276) and OTP (E-017/GR-10-239) dockets based on prudency of the costs. The Commission allowed IPL to recover its costs for the cancelled Sutherland plant over a 25-year period, with no return. The Commission allowed OTP to recover its Big Stone II costs including accrued AFUDC over a 5-year period, with no return.

The Department agreed with the Company that the total cost of $78,884,916[16] (EPU of $66,086,393 and AFUDC of $12,798,523) should be recoverable from Minnesota ratepayers for the following reasons. First, the amount Xcel proposes to recover is far less than the amount the Company originally proposed for the project in the (08-509) certificate of need docket. Second,

[14] Clark Rebuttal pp. 55-59
[15] Perkett Rebuttal p. 32
[16] This is the total company cost

when Xcel saw the costs of this EPU project increasing, the Company filed a Notice of Changed Circumstances on March 1, 2012. Thus, unless specifically challenged by another party to this proceeding, the Department agrees that the EPU costs totaling $66,086,393 and AFUDC costs totaling $12,798,523 are eligible for recovery.

The Department stated it did not agree with the Company's proposal to recover the $78.9 million over 12 years while earning a return on the asset. Instead the Department recommended that the Commission allow Xcel to recover the $78.9 million over the remaining life (RL) of the facility, which is 20.3 years; without earning a return on the asset. This adjustment provides for a reasonable sharing of the cost between shareholders and ratepayers.

The Department[17] stated that Company witness Ms. Heuer calculated the revenue requirement of its two alternatives as $4,928,000 and $4,566,000 respectively for the 12 year amortization period with no return and the 20.3 year amortization period with a debt return. [18]

The Department does not support Xcel's proposal to recover the costs, even without a return, over a period of 12 years since that period of recovery is less than 60 percent of the remaining life of Prairie Island (12/20.3 = 59.1 percent).

The Department stated that the most appropriate approach that is consistent with the Commission's prior decisions would be to allow Xcel to recover the costs of the $78.9 million abandoned plant over the 20.3 years of remaining life of PI, with no return.

However, if the Commission believes it is reasonable to allow Xcel to earn only the debt component of its cost of capital on the $78.9 million over the remaining life of the plant, such an approach should fully reflect that Xcel would forego earning any return on equity for the abandoned plant. With this approach, the amount that Xcel would be allowed to charge for debt costs over the 20.3 years of remaining life would be 2.24 percent, rather than the 4.7605 percent that the Company proposes.

The Department stated it does not recommend that approach. It offered that alternative only if the Commission believes it is worth exploring a debt-only approach. The Department concluded that the approach that would be most consistent with the Commission's previous decisions would be to allow Xcel to amortize the $78.9 million over the life of the PI nuclear power plant with no return.

Department Initial Brief at page 46:

> Resolved between DOC and Xcel: The amortization methodology. Xcel accepted a DOC alternative to Xcel's proposed recovery; the alternative would allow Xcel to earn 2.24 percent, the debt component of its cost of capital, on the $78.9

[17] Lusti Surrebuttal pp. 5-7
[18] Xcel Ex. ___ AEH-2, Schedule 10, pages 1-2 (Heuer Rebuttal).

million over the remaining 20.3 year life of the facility. This adjustment results in a total 2014 Test Year revenue reduction of $4.867 million.

OAG

Lindell Direct pp. 35-44
Lindell Surrebuttal pp. 17-24

In 2008 NSP requested a CON for an EPU for its Prairie Island ("PI") nuclear generating plant. NSP requested the EPU with the intention of adding 164 MW of power at a cost of $322 million.

The OAG[19] stated that according to Xcel witness McCall, NSP began having reservations about continuing with its plans to do the PI EPU in 2011. In early 2011, NSP learned that it would likely have less output from the uprate than was initially anticipated. In mid-2011, NSP observed increased scrutiny by the NRC for LAR[20] submittals shortly after the Fukushima nuclear disaster. In August 2011, NSP had a meeting with the NRC staff and determined that getting NRC approval would likely take longer than had been estimated earlier. However, NSP did not advise the Commission of its concerns regarding the costs and benefits of the PI EPU in 2011.

According to NSP, it had spent $57 million for the work on the PI EPU primarily for engineering and design work. NSP also explained that if the project were canceled, approximately $5 million additional would be incurred for contractual obligations with its vendor – Westinghouse. The remaining $232 million would be avoided if the project had been canceled at that time.[21]

The OAG expressed concerns with NSP's management of the CON in 2011 and NSP's Notice and Petition in March 2012. NSP did not seek expedited review of its Notice and Petition despite the need for timely consideration of the changed circumstances to avoid additional costs if the project were to ultimately be canceled. NSP was evaluating the changed circumstances during 2011 and did not file its Notice and Petition until March 30, 2012. NSP did not advise the Commission or parties that the project costs would continue to increase as time lapsed.

The OAG[22] argued that NSP should have been actively considering uprates at other utilities including cancellations for cost and engineering concerns. Ignoring this information, as NSP has claimed, contributed to the poor decisions made by NSP to continue to support the project in March 2012 in its Notice. NSP subsequently reversed its position and supported cancelation in its Supplemental Filing in October 2012.

The Commission decided on December 20, 2012 to terminate the CON. The order was issued on February 27, 2013. The Commission accepted NSP's recommendation to discontinue the uprate

[19] Lindell Direct p. 36
[20] License Amendment Request
[21] Lindell Direct p. 38
[22] Lindell Direct p. 39

project and ordered that NSP address cost recovery of its incurred costs to date in NSP's rate case that had been filed in November 2012. However, NSP failed to address cost recovery in the 12-961 rate case.

The OAG's position is that NSP made a mistake by not seeking recovery in its last rate case. NSP should have addressed cost recovery as instructed by the Commission or in the alternative requested to defer the costs incurred for the PI EPU project so that the costs could be addressed in this rate case.[23] The OAG argued that absent a request for deferral, NSP should have written-off the PI EPU costs in 2012 in accordance with FERC accounting requirements and generally accepted accounting principles ("GAAP").

The OAG argued that NSP cannot seek recovery of the $10.1 million of its PI EPU amounts that it wrote-off in 2012. The PI EPU costs were incurred over a number of years and properly accounted for as CWIP costs. Once a project has been canceled the costs must be removed from CWIP and either written-off or deferred if the Commission grants deferral.[24]

The OAG recommended that at a minimum, the costs that should be denied on a total company basis are the $10.1 million that NSP has already written off plus AFUDC costs of $12.8 million. Customers have not received any benefit from this project and allowing an AFUDC return would be unfair to them. The OAG also recommended that the remaining recoverable costs be amortized over 10 years with no return allowed on the unamortized balance of costs.[25]

The OAG[26] stated that there are differences between NSP's canceled PI EPU project and the projects for other utilities that NSP cites as precedent for cost recovery. NSP has incurred a substantial amount of costs for this project that has never been used and useful. The uprate was never completed. Furthermore, the costs continued to escalate because NSP failed to timely respond to the evolving conditions that warranted cancelation of the project. In addition, NSP continued to accrue AFUDC on this project until it was formally canceled by the Commission by order in 2013 even though the project was on hold during 2011 and 2012.

In response to the OAG's objections, NSP argued that it wrote-off the $10.1 million in 2012 to comply with GAAP accounting requirements and that GAAP accounting does not control the ratemaking treatment for the canceled PI EPU costs. The OAG disagreed, stating that unless NSP had requested to defer some or all of its costs from 2012 and prior, then it cannot now seek, in a 2014 test year, to recover those costs.

The OAG's position is that the PI EPU costs were excessive, and therefore imprudent, because NSP failed to timely cancel the project.[27]

[23] Lindell Direct p. 40
[24] Lindell Direct pp. 42-43
[25] Lindell Direct pp. 43-44
[26] Lindell Surrebuttal p. 18
[27] Lindell Surrebuttal p. 19

The Company explained that, "The Company had determined that due to the termination provisions of the Westinghouse contract, it was better to receive the deliverables of the contract by summer of 2012 as contracted than pay similar contract termination fees and receive no product." NSP's contract with Westinghouse was never terminated and costs continued to be incurred unnecessarily under that contract. The OAG's response to NSP's decision to not terminate the Westinghouse contract is that the flaw in NSP's position is that there was no benefit to continue receiving deliverables from Westinghouse. NSP's customers never received any benefit from the Westinghouse contract. NSP failed to limit the costs on the contract even though NSP had the option to terminate it and limit its contractual payment obligations. The deliverables that NSP continued to pay for, and which NSP claims was the reason for not terminating the contract, had no value to NSP and its customers and shouldn't be included in rates.[28]

Xcel argued that the OAG's recommendation to disallow the $12.8 million, representing total AFUDC from the beginning of the project in 2006 until it was abandoned in 2012 is contrary to precedent and FERC Accounting Release AR-5. The OAG stated it had reviewed the accounting for the PI EPU project and FERC accounting requirements and revised its initial recommendation to disallow $12.8 million of AFUDC. The OAG recommended instead that $9.2 million of AFUDC (total company basis) be disallowed for recovery which represents the AFUDC accrued for 2011 and 2012. Starting in 2011, NSP was questioning the viability of the project and ultimately it was determined that the project was not viable. Furthermore, as explained in direct testimony, the EPU project was no longer on-going beginning in 2011.[29]

Minnesota Chamber of Commerce

Schedin Direct pp. 10-11
Schedin Surrebuttal pp. 6-7

The MCC[30] stated that that under the circumstances of this project, ratepayers should be not paying the Company ROE on this project. The MCC recommended that the recovery period be extended to 20 years, the life extension recently approved by the NRC for both Prairie Island Units but with only one half year recovery beginning in 2014. This treatment is similar to the 21 year recovery of deferred depreciation from Sherco 3.

The MCC[31] stated that Xcel summarized the result of its recommendation for the 2014 revenue requirements for the MN jurisdiction. The recommendation would reduce the requirement from $8.595 million to $3.120 million, a reduction of $5.475 million.

The MCC stated it does not oppose the recommendation of the Department to recover the costs over 20.3 years, without earning a return on the asset.

---

[28] Lindell Surrebuttal pp. 20-21
[29] Lindell Surrebuttal pp. 22-23
[30] Schedin Direct pp. 10-11
[31] Schedin Surrebuttal pp. 6-7

In its initial brief, the MCC stated that the Company accepted the proposal by the Department to recover the costs over the remaining life of the facility with a carrying cost of 2.24%. The Chamber does not object to this proposal.

ICI Group

Glahn Direct pp. 10 -12
Glahn Surrebuttal pp. 2-3

The ICI[32] stated that plans to increase the Prairie Island facility's output were abandoned by Xcel before completion. Accumulating costs for a project that was never put into service raises the question as to whether the funds expended on the cancelled project represent a "used and useful" asset.

The used and useful investment principle states that in order for costs associated with a utility's investments in plant or other property to be included in customers' rates, the investment must be used to provide utility services and must be useful in the provision of utility services. Some utility investments are used but not useful and some are useful but not used. For example, a generating plant may be useful, but if electric loads are not great enough, it may never be used, and thus would be excess investment.

With the Prairie Island EPU there is a unique instance where the underlying facility has been used in the production of power for many years, but planned improvements did not occur, even though considerable costs were expended. The uprate project is not useful for making electricity nor has it been used at any point in time.

The ICI argued that by granting cost recovery to cancelled projects, the Commission would encourage utilities to pursue imprudent or marginal projects, with the assurance that they would be made whole, regardless of the outcome. Because the Prairie Island EPU project was never used and useful asset to ratepayers, the Commission should not allow any recovery of costs associated with the now cancelled project. Consumers should not pay for an asset from which they are not receiving benefits.

If the Commission does allow recovery of these costs, they should be amortized over the 20 years remaining on the plant's operating licenses, rather than the six to twelve years proposed by Xcel.

If the Commission does allow a return on these assets during their amortization, the rate should reflect the nearly risk-free aspect of the now abandoned project. Rather than having the company's usual rate of return applied to the asset, the return, if any, should be something closer to a U.S. Treasury bill or bond interest rate.

[32] Glahn Direct p.10

In Surrebuttal, the ICI[33] noted that Xcel now suggests a twelve-year amortization period with no return during that period and that if a return is allowed the Company would apply a debt rate of return. The ICI stated that while preferable to using a full cost of capital return, using a debt return still rewards the utility with a return reflecting a risk level that they are not assuming with the recovery of such a regulatory asset. While a twelve-year recovery with no return would be preferable to their original proposal, the ICI continued to believe that Xcel has not met its burden to justify recovery of these amounts, regardless of time period.

ALJ Report

Findings 427-462

462. Before analyzing whether the EPU Project costs were prudently incurred, it is necessary to first address the threshold issue posed by the OAG: namely, whether the Company should be permitted to seek recovery of its EPU Project costs in this case at all given that the Company has not requested deferred accounting of its EPU Project costs. In its 12-961 ORDER, the Commission expressly authorized the Company to seek recovery of these costs in this rate case when it stated: "The Company will be required to fully justify its request for rate reimbursement of project costs in its next rate case." The Commission did not require the Company to request deferred accounting first. Based on the clear language in the 12-961 ORDER, the Administrative Law Judge concludes that the Commission intended to allow the Company to seek recovery of these costs in this rate case. This conclusion is consistent with the Commission's decision in the IPL case, discussed above, wherein the Commission stated that it "does not view the question of cost recovery ... as controlled by an accounting issue."

463. The next issue to be addressed is whether the Company has demonstrated that its EPU Project costs were prudently incurred in good faith. Based on a careful review of the record, the Administrative Law Judge concludes the Company has met its burden. The record shows that at the time the CON was issued and the Company first undertook the EPU Project, the EPU Project was determined to be a cost-effective means of addressing a projected increase in demand. While circumstances changed after the Commission issued the CON for the EPU Project, the Company's cost/benefit analysis continued to show a positive value for the Project in March 2012 when the Company filed its Notice of Changed Circumstances. In comments filed in June 2012, the Department agreed that the EPU Project remained cost-effective and recommended that the Commission allow the EPU Project to continue. The Department's position was based on its own independent analysis. In October 2012, based on new information and further analysis, the Company notified the Commission that it had concluded that the EPU Project should be suspended because, in the view of the Company, the outstanding risks of delay and increased cost outweighed the small benefit of proceeding with the EPU Project.

[33] Glahn Surrebuttal pp. 2-3

464. During the course of the Company's continuing review of the costs and benefits of the EPU Project, the Company took steps to minimize costs. The Company prudently suspended all work on the EPU Project, with the exception of the Westinghouse work, when it appeared the EPU Project would have only a marginal net benefit. The Company explained that its contract with Westinghouse would have required payment regardless of whether Westinghouse was permitted to continue work because of the early termination clauses. While the OAG challenges the prudence of the termination liability clauses in the Westinghouse contract, its criticism rests entirely on hindsight and is speculative. The requirement for recovery is that the utility's actions must be reasonable and undertaken in good faith. The Company has met this standard.

465. Similarly, there is no basis for excluding AFUDC prior to the Commission's oral cancelation of the Project in December 2012. The OAG's argument rests on its suggestion that the Company should have known that the EPU Project was not viable as early as August 2011 when the Company met with NRC staff and learned that the Project licensing would likely take longer and be more costly than expected. The OAG's argument, however, ignores the fact that both the Company and the Department conducted a detailed cost/benefit analysis in 2012 and determined that the Project was still viable. For these reasons, the Administrative Law Judge concludes that the Company should be allowed to recover its Prairie Island EPU Project costs, including accrued AFUDC. The OAG's arguments to the contrary are without merit.

466. Nor does the Administrative Law Judge agree with the OAG's suggestion that the Company be barred from recovering the 2012 pre-tax charge of $10.1 million related to EPU Project costs. The $10.1 million pre-tax charge does not represent a "write-off' as the OAG asserted but rather reflects the Company's judgment that recovery of a return on the EPU Project costs is not certain given past Commission decisions. The Commission's decision in this case will remove that uncertainty and the Company's accountants will make any necessary adjustments to reconcile the Company's estimate with the Commission's ultimate disposition.

467. Having determined that the Company should be allowed to recover its Prairie Island EPU Project costs, including AFUDC, the remaining issues for determination are: (1) the time period for cost recovery; and (2) whether the Company should be allowed a return on those costs. The Administrative Law Judge concludes that recovery over 20.3 years with a debt only return of 2.24 percent reflects a reasonable outcome for both ratepayers and shareholders. If completed, the Prairie Island EPU Project would have served ratepayers throughout the remaining life of the facility, which is currently 20.3 years. Thus, a 20.3 year recovery period for the investment is reasonable. Given that the recovery period is approximately 20 years, the Administrative Law Judge concludes that it is reasonable to allow a debt-only return of 2.24 percent, as agreed to by the Department and Company. A debt-only return properly recognizes the time value of money.

Xcel Exception to the ALJ Report

Xcel filed comments stating that the ALJ made the appropriate decisions in accepting the agreement between the Company and the Department and in rejecting the OAG’s arguments.

OAG Exceptions to ALJ Report

While the OAG disagrees with several of the ALJ's conclusions, the OAG specifically takes exception to Findings 465 and 467.

In Finding 465, the ALJ recommended that Xcel be permitted to recover all AFUDC that was accrued until the Commission's oral cancellation of the project in December 2012. The OAG takes exception to this recommendation because the ALJ did not properly analyze the recovery of AFUDC under FERC accounting rules.

The Commission is required to follow all of FERC's accounting rules. According to these mandatory rules, Xcel is only permitted to accrue AFUDC when the Prairie Island EPU was both "viable" and "ongoing." Any AFUDC accrued when the EPU project was either not viable or not ongoing must be disallowed under mandatory FERC accounting rules.

The OAG takes exception to the ALJ's recommendation on this issue because the ALJ limited her analysis to whether the Prairie Island EPU was "viable," and did not analyze whether the Prairie Island EPU was "ongoing." The record in this matter, and the ALJ's prior Findings make clear that the Prairie Island EPU was not "ongoing" by, at the latest, the fourth quarter of 2011. Multiple Company witnesses testified that Xcel suspended work on the EPU after a meeting with the NRC on August 18, 2011.

The fact that Xcel allowed Westinghouse to complete its contract does not change the fact that the project was not ongoing, because Xcel admitted that the primary reason Westinghouse was allowed to complete the contract was that the contract included significant termination penalties.

By August 18, 2011, or at the latest the end of 2011, FERC accounting rules, which the Commission must follow, required Xcel to stop accruing AFUDC because the project was no longer "ongoing."

Xcel Should Not Recover a Return on Canceled Project Costs. In Finding 467, the ALJ concluded that Xcel should be permitted to recover the costs of the Prairie Island EPU over a period of 20.3 years with a debt only return of 2.24 percent. The OAG does not object to the length of the recovery, but takes exception to the ALJ's recommendation to allow Xcel a return on cancelled project costs. The Commission's previous cases establish a clear precedent for allowing a utility to recover the costs of a cancelled project without a return.

According to the Minnesota Supreme Court, "an agency [like the Commission] must generally conform to its prior norms and decisions or, to the extent that it departs from its prior norms and decisions, the agency must set forth a reasoned analysis for the departure that is not arbitrary and capricious."

Accordingly, the OAG takes exception to Finding 467, and recommends that it be modified to reflect that any recovery of cancelled project costs for the Prairie Island EPU will be with no return.

ICI Exceptions to the ALJ Report

At the evidentiary hearing, the Company stated that it would accept cost recovery amortized over 20.3 years (or the facility's remaining life), with a 2.24 percent, debt-only return. While such a voluntary reduction in its request for the amount of cost recovery may cause the Company's current request to appear *subjectively* more reasonable, it does nothing to prove that the request results in *objectively* just and reasonable rates.

The ICI Group takes exception to these findings and conclusions because (1) there should be no cost recovery allowed for this project because it was never "used and useful," and (2) if cost recovery is allowed, the costs associated with the Westinghouse contract should not be recoverable from ratepayers.

The ICI Group contended that: "By granting cost recovery to cancelled projects, the Commission would encourage utilities to pursue imprudent or marginal projects, with the assurance that they would be made whole, regardless of the outcome."

"Under general principles of utility law, the used and useful standard simply requires (1) that the property be in service, and (2) that it be reasonably necessary to the efficient and reliable provision of utility service." "To consider such a nonexistent plant as used and useful is an unreasonable expansion of the used and useful concept. The plant in question has not provided and never will provide electricity to rate payers."

The ICI Group urges the Commission to determine, in its legislative capacity, that the Prairie Island EPU Project is not used and useful, and to disallow any cost recovery for the project.

In the event the Commission determines that the costs associated with the cancelled EPU are recoverable, it should disallow recovery for costs associated with the Westinghouse contract in the exercise of its quasi-judicial powers.

Staff Analysis

Xcel is requesting that the Commission allow it to recover a total of $78.9 million in cost for the terminated Prairie Island EPU project. The goal here is to determine what is an appropriate balancing of the interest of ratepayers and the Company.

The underlying Prairie Island facility has been used in the production of power for many years, but the planned EPU did not occur, even though considerable costs were expended. The uprate project is not useful for making electricity nor has it been used at any point in time. Under normal circumstances there would be no recovery for plant that is not used and useful.

The $78.9 million in costs will never produce a benefit for ratepayers. They will never receive electric service as a result of the costs. They are being asked to pay that amount essentially for nothing.

Xcel made the expenditures in the pursuit of an EPU for the Prairie Island nuclear plant. The Commission had approved a CON for that project. The expenditures were made in good faith.

There are two recent cases where the Commission has addressed similar requests. The one that is most like the current case was for IPL's Sutherland Generation Station which was to be a baseload coal fired power plant to have been located in Marshalltown, Iowa. At the time the project was terminated, there were no construction or equipment costs associated with the project, all the costs were planning and investigations costs. The ALJ in Docket E-001/GR-10-276, found that in the absence of a Commission order granting deferred accounting status, all capitalized costs incurred prior to the test year should not be recoverable. However, the Commission authorized recovery of $1,671,185 in Minnesota jurisdictional costs for the Sutherland plant, to be amortized over a 25 year period, roughly approximating the period over which these costs would have been recovered had the plant been built, with no return.

The second case was Otter Tail Power's request to recover costs related to a proposed transmission project in Docket No. E-017/GR-10-239. In that case the Commission concurred with the Administrative Law Judge that the Big Stone II project costs were prudently incurred, are recoverable from ratepayers, and should be amortized over a five-year period with no return on unamortized amounts.

In Surrebuttal, the Department recommended recovery over the 20.3 year life of the plant with no return. However, while it did not recommend that approach, the Department offered an alternative of a debt-only approach only if the Commission believed it would worth exploring. At the evidentiary hearing, both the Company and the Department agreed upon the debt only approach although the Department provided no explanation for the change in its recommendation.

As previously mentioned, the goal is to appropriately balance the interests of the ratepayers and the Company. Staff believes that the previous decisions, which allowed the company to recover the costs over the remaining life of the plant with no return, accomplished that goal. The ALJ concluded that it is reasonable to allow a debt-only return of 2.24 percent as that properly recognizes the time value of money. The time value of money should not be a concern here. Allowing this would be just the first step in a process that would allow the Company to not only recover its costs is a situation like this but also earn the full rate of return. Such a result would be totally inappropriate. The proposal to allow recovery over the life of the plant with a debt only (2.24%) return tips the scale more heavily to Xcel.

Under FAS 90, when it becomes probable that an operating asset under construction will be abandoned, the utility should remove the cost of that asset from construction work in progress (CWIP) and determine whether recovery of any cost will be allowed by the regulatory authority. Any disallowance of all or part of the cost of the abandoned plant that is both “probable” and “reasonably estimable” shall be recognized as a loss. FAS 90 specifically instructs that the “remainder of the cost of the abandoned plant shall be reported as a separate new asset.” Finally, FAS 90 instructs that the determination on future recoverability should focus on the facts and circumstances related to the specific abandonment and should also consider the past practice and current policies of the regulatory jurisdiction on abandonment situations.

According to the Company, it was able to convince it auditors that there was Commission precedence that would allow recording the PI EPU costs as a regulatory asset. The cases it used as precedence were the IPL Sutherland case and the OTP Big Stone II transmission line case. In both those instances the abandonment costs were incurred in the test year. That made them test year costs rather than out of period costs. Because Xcel abandoned the PI EPU in 2012 those cost would not be test year costs for Xcel in any test year after 2012. The Company did not provide an explanation of how the different circumstances made the IPL and OTP cases precedent cases that would support recovery.

As discussed by Xcel it recorded a $10.1 million reduction of the asset in 2012. The OAG argued that absent a request for deferral, NSP should have written-off the entire PI EPU costs in 2012 in accordance with FERC accounting requirements and generally accepted accounting principles (“GAAP”). The OAG also argued that NSP cannot seek recovery of the $10.1 million of its PI EPU amounts that it wrote-off in 2012.

The Company argued that the OAG recommendation would double account the effect of the $10.1 million charge already recorded by the Company. However, the discussion and schedules of Xcel witness Weatherby's Surrebuttal on pages 5-8 shown that the total costs amortized/recovered over 12 years would be $78.9 million without the OAG's recommended disallowance and $68.8 million with it. That appears to be the intent of the OAG's recommendation and that the double accounting would be for accounting and not ratemaking.

Decision Alternatives

Recovery of the Prairie Island EPU Costs

1. Allow the Company to recover the $78.9 million cost over the 20.3 year life of the plant with a debt return of 2.24%. (ALJ, Xcel, DOC, MCC)

2. Allow the Company to recover the $78.9 million cost over the 20.3 year life of the plant with no return.

3. Allow the Company to recover the $78.9 million cost less $10.1 million previously written off and less $9.2 million of AFUDC over the 20.3 year life of the plant with no return. (OAG)

4. Do not allow the Company to recover any of the $78.9 million cost of the PI EPU. (ICI)

(Note: The decision alternatives for this item correspond to alternative VII, A (1 through 4) on p. 40 of the deliberation outline.)

Babcock & Wilcox Nuclear Energy, Inc. Lawsuit

PUC Staff: Jerry Dasinger

OAG Request

On January 20, 2015, the OAG submitted a letter. The OAG stated its investigation has uncovered some issues of concern, and for that reason the OAG seeks the Commission's guidance on how to address this issue. On November 12, 2014, Northern States Power Company ("Xcel" or "the Company") and SNC-Lavalin Nuclear (USA) Inc. ("SLN") were sued in Goodhue County District Court by Babcock & Wilcox Nuclear Energy, Inc. ("BWNE"). BWNE's primary allegation is that Xcel has withheld payment of approximately $45.3 million for work performed on the Replacement Steam Generator (RSG) project.

Based on the responses to the OAG's information requests, and the documents filed in the lawsuit, the OAG can provide the following summary:

- In its 2012 rate case filed on November 2, 2012, Xcel included $285 million in the 2013 test year rate base for costs related to the Replacement Steam Generator (RSG) project that Xcel believed would be placed in service during 2013.

- Sometime after December 24, 2013, Xcel received invoices that included the $46 million in costs that is disputed in the lawsuit. After receiving the invoices, Xcel withheld payment; Xcel has not paid any portion of the $46 million to BWNE.
- In its discovery responses, Xcel indicated that a portion of the disputed cost was included in rate cases. In its Answer to BWNE's Complaint, Xcel claims that it does not owe any portion of the $46 million to BWNE.

The OAG expressed several concerns. First, regardless of whether it was reasonable for Xcel to include some portion of this $46 million cost in its projected 2014 test year, it is now clear that Xcel has not paid any of the $46 million. As such, Xcel's rate increase request includes a substantial investment in the RSG project that Xcel had not paid at any time during the 2014 test year. If Xcel's projected 2014 test year rate base is approved, Xcel's rates will include earning its full rate of return on costs that Xcel has not paid, and that Xcel claims in signed legal documents it does not owe.

Second, BWNE is charging interest on the unpaid invoices at the rate of 18%, which amounts to more than $22,000 per day. If Xcel is ultimately unsuccessful in defending the lawsuit, it is likely that Xcel will seek to recover these interest payments from ratepayers. The OAG has been unable to assess whether it is reasonable for Xcel to permit the interest to continue to accrue because Xcel has repeatedly refused to provide the contracts and subcontracts at issue in the lawsuit.

Third, Xcel did not inform the Commission or any interested parties about its dispute with BWNE, and that Xcel has refused to respond fully to the OAG's information requests. The dispute is over a relatively large sum of money, and Xcel became aware of the dispute sometime in early 2014, or possibly when the installation work was being done at the end of 2013.

The OAG stated it believes that the Commission could proceed down several paths. First, the Commission could determine that, based on this information, Xcel has not supported its request to include a portion of the disputed $46 million in rate base at this time.

Second, the Commission could determine that the issues surrounding the contractor dispute should be resolved in a separate docket.

Third, the Commission could require Xcel to make an adjustment for the unpaid $46 million in the resolved process for the 2014 Plant Related Revenue Requirement True-Up.

The OAG requested that the Commission provide guidance on how it wants the parties to pursue resolution of the issues raised by the dispute between Xcel and BWNE. The OAG also requested that the Commission direct Xcel to respond in a complete and timely manner to the OAG's information requests on this issue.

Department Comments

On February 2, 2015, the Department filed comments stating first, the Department believes the Commission should direct the Company to fully respond to the OAG's information requests in this proceeding regarding the dispute. Second, the Department plans to review the Company's initial comments regarding their proposed procedure to handle the dispute within the current rate case; and will file reply comments on February 10, 2015.

Xcel Comments

On February 3, 2015, Xcel filed comments stating the Company filed the current rate case on November 4, 2013 and included a full year of revenue requirements associated with the Prairie Island Replacement Steam Generator (RSG) in its 2014 test year.

After issuing a request for proposal, it selected SNC-Lavalin Nuclear (USA) Inc. (SNC-Lavalin) as the primary contractor. SNC-Lavalin engaged Babcock & Wilcox Nuclear Energy, Inc. (BWNE) as its subcontractor to perform most of the installation work.

On January 20, 2014, the Company received invoices related to the RSG project from SNC-Lavalin, which did not include invoices from the subcontractor BWNE. As reflected in the Company's Answer to the Complaint, SNC-Lavalin did not forward any BWNE invoices to Xcel Energy from January 2014 through mid-May 2014. SNC-Lavalin first started submitting invoices for work performed by BWNE around that time. Xcel continued to receive invoices through mid-October 2014.

According to Xcel, after receiving the majority of invoices, the Company tried to resolve the disputed issues with SNC-Lavalin and BWNE. It met with these parties, but was unable to reach agreement. BWNE filed its Complaint on November 12, 2014.

In response to the OAG's concerns that it did not advise the Commission or its stakeholders of the dispute with BWNE, Xcel stated that for a significant portion of the discovery period, it had not even received invoices from BWNE.

The Company stated it did have concerns about vendor performance and the amount owed. It fully anticipated these concerns to be addressed through the normal course of dispute resolution discussions post receipt of final bills.

Procedural Guidance

The OAG has proposed three procedural options. The first option would find that the Company did not support its request to include any portion of the disputed amount in 2014 final rates. Xcel stated it appreciates the OAG's suggestion, as well as its willingness to allow the Company to first provide more information, it does not support the first option. Xcel noted there is rarely perfect matching between test year costs and actual results. As a result, when using a forward looking test-year, many circumstances can arise that can cause a forecast to deviate – upward or downward – from actual costs.

The OAG's second option would result in an additional fact-finding on this issue in the current case or by opening a new docket. The dispute between the Company and BWNE is now pending in district court. BWNE is alleging misrepresentations before regulatory bodies, which the Company denies, to leverage its litigation position. A separate regulatory investigation could complicate efforts to prosecute its litigation, which if a favorable resolution is reached will result in its customers benefitting.

The last option would incorporate the disputed amount into the 2014 Plant Related Revenue Requirement True-Up process (2014 Capital True-Up). The Company stated it is willing to agree to take this issue up in the context of the 2014 Capital True-Up process. Since there is a true-up process available, Xcel believes it can include the effect of the RSG disputed costs as part of a holistic view of its overall capital costs.

The Company stated it did provide responses to the majority of questions presented by the OAG. However, as noted in response to OAG IR 642, it objected to the OAG's request for copies of the contracts. The issue in front of the Commission is how to address the costs for the RSG project – currently in-service and performing as expected – in our 2014 and 2015 rates. Any request for the contracts would go to the merits of our costs and is untimely. In addition, the contracts are subject to confidentiality provisions that create certain limits on their disclosure. Xcel stated it made a mitigating offer to the OAG as a means of resolving their concerns, but maintained that the interpretation of these contracts and the current dispute between the Company and BWNE is being litigated in district court.

Department Reply Comments

On February 10, 2015, the DOC filed comments stating:

Xcel's proposal to address in the true-up any refund from the litigation process is not entirely clear (for example, it is not clear what would happen if the litigation issues are not resolved before the end of 2015). However, such an approach may be feasible, provided that Xcel agrees to refund to Xcel's ratepayers any favorable outcome from the litigation, even if the litigation is not resolved until a later date.

With regard to the OAG information requests, the Company stated at Page 4 of its comments:

> …the Company noted that many of the OAG's information requests did not relate to the BWNE Complaint and, since the evidentiary process was closed, were untimely. Nonetheless, the Company did provide responses to the majority of questions presented.

Also at Page 4 of its comments, the Company stated:

> However, as noted in response to OAG IR 642, we object to OAG's request for copies of the contracts….In addition, the contracts are subject to confidentiality provisions that create certain limits on their disclosure. We made a mitigating offer to the OAG as a means of resolving their concerns…

The Company did not explain either the confidentiality provisions or what mitigating offer it made to the OAG as a means of resolving their concerns. The parties may indicate more information in their reply comments for the Commission's consideration.

Another item that is missing from the Company's comments is whether or not Xcel objects to any information requests other than OAG IR 642. The Department notes from its review of the information request responses attached as Exhibit C to OAG's January 20, 2015 letter to the Commission in this matter that Xcel may not have fully responded to OAG 643 (which requested an accounting for all work performed by and invoices received from BWNE and SNC-Lavalin Nuclear Inc.).

OAG Reply Comments

On February 10, 2015, the OAG filed reply comments.

The OAG stated that Xcel should have informed the Commission and interested parties about the dispute with BWNE. In the Commission's Multi-Year Rate Plan ("MYRP") Order, the Commission required that all utilities filing a MYRP provide the Commission with prompt updates about changes to capital projects included in the MYRP. While the amounts disputed with BWNE do not precisely fit the reporting requirements of Order Point 29, they are sufficiently analogous that Xcel should have informed the Commission and other parties about the dispute, and the fact that Xcel had included a significant, unpaid expense in the rate case, much sooner. In his direct testimony, Xcel witness Mr. Chris Clark provided a guarantee that Xcel would "file a notice with the Commission and interested parties within 30 days of a material change to any project included in the multi-year rate plan." The fact that Xcel did not pay, and does not intend to pay, a significant sum that was included in its projected test year is a material change under any definition.

The OAG had suggested that the Commission could order Xcel to "make an adjustment" for the disputed costs in the 2014 true-up that was agreed to between the Department and Xcel. Based upon Xcel's Initial Comments, the OAG understands that Xcel has offered to include the disputed RSG costs along with other canceled and postponed projects in the true-up mechanism.

However, after reviewing all of the testimony and transcripts about the 2014 true-up mechanism and conferring with the Department, the OAG stated it is still unclear how the mechanism will function, or whether the 2014 true-up will satisfy the requirements of the Commission's MYRP Order.

Specifically, the MYRP Order requires Xcel to identify any capital projects included in the MYRP that are canceled or postponed, and file a proposal within 30 days to adjust current rates and refund any costs already collected. The MYRP Order focuses on individual projects included in the MYRP, and requires Xcel to take action on projects that are canceled or postponed. Rather than reviewing whether individual projects were canceled or postponed, Xcel's proposal would be based on aggregate, or "holistic," capital spending over the MYRP period. It appears that, under Xcel's proposal, Xcel would not make any refund or adjustment related to canceled or postponed projects as long as Xcel's capital spending is equal to, or greater than, its projected capital spend.

For that reason, the OAG recommends that the Commission establish specific instructions for the true-up mechanism to ensure that it complies with the MYRP Order, regardless of whether the Commission takes action on the disputed RSG costs. To the extent that the Commission establishes procedures for the true-up that comply with the MYRP Order, the OAG agrees that including the disputed RSG costs in the true-up mechanism would be a reasonable way for the Commission to resolve the matter.

Staff Analysis

Xcel did not provide the contracts requested by the OAG in IR 642. According to the OAG, BWNE is charging interest on the unpaid invoices at the rate of 18%, which amounts to more than $22,000 per day. The OAG was unable to assess whether it is reasonable for Xcel to permit the interest to continue to accrue because Xcel has refused to provide the contracts and subcontracts at issue in the lawsuit. Xcel stated that the contracts are subject to confidentiality provisions that create certain limits on their disclosure. It made a mitigating offer to the OAG as a means of resolving their concerns, but maintained that the interpretation of these contracts and the current dispute between the Company and BWNE is being litigated in district court.

The OAG's issue appears to be whether the interest costs could or should be charged to ratepayers. The Commission could direct Xcel to provide the OAG with the relevant sections of the contracts that would govern the interest charges. The Commission could direct Xcel to provide discussion and analysis on these charges in the first rate case it requests recovery of the interest charges. The Commission could require Xcel to make a compliance filing providing all relevant information as to costs and interest paid to BWNE once the lawsuit is resolved and discuss what costs were included as plant in service in the current rate case. The Commission could make a determination here that any interest paid to BWNE resulting from these unpaid invoices can't be recovered from ratepayers at any time.

The parties agreed that the rate recovery of any costs for the BWNE contract that are included in this rate case that the lawsuit determines are not owned by Xcel, should be refunded. The lawsuit may not be resolved when the true-ups for 2014 and 2015 are finalized. Staff suggests that the Commission require Xcel to make any necessary refund when the lawsuit is resolved if that occurs after the true-ups for 2014 and 2015 are finalized.

Decision Alternatives

Babcock & Wilcox Nuclear Energy, Inc. Lawsuit

Information Requests

1. Direct Xcel to provide the OAG with the contracts as requested in IR 642.

2. Direct Xcel to provide the OAG with the relevant sections of the contracts that would govern the interest charges.

3. Direct Xcel to provide discussion and analysis on these interest charges in the first rate case it requests recovery of the interest charges.

4. Require Xcel to make a compliance filing providing all relevant information as to costs and interest paid to BWNE once the lawsuit is resolved and discuss what costs were included as plant in service in the current rate case.

5. Determinate that any interest paid to BWNE resulting from these unpaid invoices can't be recovered from ratepayers at any time.

Disputed $46 million in Rate Base

6. Determine that, based on the information in the OAG's letter, Xcel has not supported its request to include a portion of the disputed $46 million in rate base at this time so recovery is not allowed in this rate case in the 2014 test year and 2015 Step.

7. Determine that the issues surrounding the contractor dispute should be resolved in a separate docket

8. Require that any costs included in rate base but not paid be refunded as part of either the 2014 or 2015 refunds. If the lawsuit is not resolved at either of those times, then the refund should be made within 60 days after the lawsuit is resolved.

Refund Plan

9. Require Xcel, the Department, the OAG and any other interest party develop the details and procedures of a refund plan for the MYRP that is consistent with the requirement to identify any capital projects included in the MYRP that are canceled or postponed, and file a proposal within 30 days to adjust current rates and refund any costs already collected. Require that a compliance filing describing the resulting plan be made within 45 days of the Order in this docket.

(Note: The decision alternatives for this item correspond to alternative VII, B (1 through 9) on pp. 40-41 of the deliberation outline.)

Nuclear Refueling Outage Cost Amortization (2015 Step)

PUC Staff: Jerry Dasinger

Xcel

O'Connor Direct pp. 118-127
Clark Rebuttal pp. 34 – 36
Clark Surrebuttal pp. 3-6

The Company[34] stated that the only refueling outage scheduled in 2014 is for Prairie Island Unit 1. There were two refueling outages in 2013 with partial costs of each of these outages included in the test year as shown in the following table.

[34] O'Connor Direct p118 & 120

Outage Costs included in 2014 Test Year Amortization Expense
($ in millions)

Unit/Year	PI Unit 1/ Fall 2012	MT/ 2013	PI Unit 2/ Fall 2013	PI Unit 1/ Fall 2014	Total
Outage Duration in Number of Days	71	138	98	33	
Total Outage Cost	$42.1	$63.3	$55.1	$41.5	
Portion included in 2014 Amortization Expense	$18.1	$34.5	$30.1	$6.6	$89.3

According to the Company, there are no capital costs or regular O&M expenses included in the outage budget. During an outage, there are three types of activities:

- Outage work, with costs tracked separately via work orders and special codes;
- Capital projects, with costs tracked in separate capital work orders; and
- Non-outage, non-capital work, which is accounted for as a regular O&M expense.

Xcel[35] stated it disagreed with the Departments recommended adjustment to decrease the amount of nuclear outage costs included in the 2015 Step for several reasons. First, it believes this proposal is inconsistent with limiting non-capital cost changes included in the 2015 Step to those changes directly related to projects included in the Step. Nuclear amortization expenses constitute a separate O&M expense, and the decline in amortization expense does not arise from projects placed in service during 2015.

Second, these costs are not considered capital-related costs. To the extent outage costs are capital-related, they are captured under the individual projects and subject to their own accounting rules and recovery treatments.

Third, 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 its customers. Finally, like the passage of time and retirement adjustments proposed by the Department, this proposal includes a single element of cost reduction without recognizing that other, rising costs are not included in the Company's 2015 revenue deficiency for purposes of this case. Taking a broader view of the Step to balance the Department's proposals with higher costs elsewhere would require inclusion of other non-capital adjustments in the Step, and would result in a higher overall revenue deficiency for 2015.

Xcel[36] argued that its requested revenue requirement for the 2015 Step does not include all of its changes in cost of service. It believes that a symmetrical approach to ratemaking would

[35] Clark Rebuttal pp. 34 – 36
[36] Clark Surrebuttal pp. 3 - 6

recognize that if the scope of the 2015 Step is expanded to include costs that are declining, it must also be expanded to include a number of costs that are rising.

According to the Company, the limited cost of service adjustments it has accepted reduced the Company's revenue deficiency. For example, in Rebuttal Testimony it accepted the Department's proposals to include Production Tax Credits for the Pleasant Valley and Border Winds projects in base rates subject to true-up, and limit non-capital costs included in the Step to those costs that are directly related to Step projects.

This approach has several benefits, including that it somewhat simplifies a complicated case; is true to the concept of representative test years; and recognizes that costs will both increase and decrease in any given year. For example, it has not proposed to update its case for increases in its nuclear fees or its active health care costs, despite the significance of those increases.

Department of Commerce

Campbell Direct pp. 61-67

The Department stated that the total outage amortization expenses included in the 2014 test year are $89.3 million. The total outage amortization expenses for 2015 are $81.8 million which is a decrease of $7.5 million. The Company's response to why it did not update the 2015 step revenue requirement for this incremental difference (2014 less 2015) for nuclear outage amortization expense is:

> The Company's 2015 Step represents the incremental revenue requirements on select step projects. . . . The limited scope of the 2015 Step was intended to help facilitate review while incorporating the major capital cost drivers of the 2015 deficiency at a level less that would have been requested if all components of rate base and expense were included.

The Department disagreed that reflecting the proposed decrease in outage amortization expense in 2015 is unreasonable.

First, the Commission's June 17, 2013 Order stated the following in Ordering Point 1 A and B:

> 1. A utility may propose a multiyear rate plan to improve the regulatory process for the recovery of –
>
> A. Costs related to specific, clearly identified capital projects, and
>
> B. Appropriate non-capital costs.

The Department stated it considers this language to support an adjustment to recognize the reduction in nuclear amortization expense from 2014 to 2015. Nuclear amortization is a cost that is clearly related to specific capital projects and further is a rate base item.

Second, the Company has requested recovery of 36 capital projects for the 2015 step that total $68.865 million revenue requirement increase, with nine of these projects being nuclear capital projects. Additionally, the Company proposes to increase expense materially.

Third, the Company will not incur the higher 2014 amortization outage expense in 2015, so it is unreasonable for ratepayers to pay for this higher 2014 amount in 2015.

The $7.5 million NSPM jurisdictional adjustment times the 74.0 percent 2015 nuclear allocator results in a $5.5 million Minnesota jurisdictional downward adjustment for nuclear outage amortization expense for 2015 step.

In Surrebuttal, the Department[37] stated it mistakenly believed that the nuclear outage amortization costs were related to capital expenditures. However, it now agrees with the Company that the nuclear outage amortization costs are related to O&M fuel outage expenses and are not capital costs. The capital nuclear costs are excluded from these O&M expenses for nuclear outage amortization. The Department stated it is no longer recommending a $5.5 million reduction in nuclear outage amortization expense for 2015.

OAG

Lindell Rebuttal pp. 5-6

The OAG[38] stated it has concerns with NSP's proposed rate increase for 2015 related to nuclear refueling outage (NRO) expenses. The DOC identified NRO expenses for 2015 that decreased from the level of expenses for 2014. However, NSP declined to recognize the reduced NRO expenses for its 2015 step increase in the amount of $7.5 million on a total company basis.

The OAG stated it does not agree with NPS's argument that the limited scope of the 2015 step increase was intended to facilitate review of proposed 2015 costs and to only recognize the major cost drivers for 2015. The OAG argued that the reduction in NRO expenses should be recognized for 2015. Step increases include both capital costs and depreciation expense for the second year of a multi-year rate plan. Both depreciation and amortization expense should be similarly recognized in the step increase. NSP included additional depreciation expense in its step increase for 2015 and amortization expense should be treated the same.

In essence the NRO costs are being treated, for accounting and ratemaking purposes, as nuclear plant capital projects because it uses a deferral and amortization expense method of accounting.

[37] Campbell Surrebuttal pp. 14- 17
[38] Lindell Rebuttal pp. 5-6

NSP earns a return on its NRO expenses just like it does for other capital projects. For these reasons the OAG fully supports the adjustment to reduce NRO expenses by approximately $5.5 million for 2015.

OAG (Lindell) Evidentiary Hearing Opening Statement:

> The nuclear refueling outage expenses are a known and measureable change and should be recognized to set rates. While Xcel argues that other nuclear O&M expenses, that increase its revenue requirement, Xcel argues that nuclear refueling outage expenses should not be treated differently by excluding them in the 2015 revenue requirement. The OAG disagrees with the asymmetrical treatment of nuclear O&M expenses. The OAG also disagrees that somehow these specific, reduced nuclear O&M expenses should be treated differently because of the Commission's multi-year rate plan requirements.

ALJ Report

Findings 514-523

520. In the MYRP ORDER, the Commission determined that requiring an examination of all expenses in each step year would defeat the goal of promoting administrative efficiency through a MYRP. For that reason, the Commission limited the adjustments in the test year revenue requirement to capital-related expenses.

521. The record in this case demonstrates that the nuclear amortization expenses at issue are not capital-related expenses, but are refueling O&M expenses. Pursuant to the MYRP ORDER, these expenses are not subject to adjustment in the 2015 Step revenue requirement.

522. In addition, even if an adjustment were made to reflect the decrease in this O&M expense as the OAG recommends, then similar adjustments would also need to be made to all other non-capital related O&M expenses; some of which likely will go up in 2015. Such symmetry is necessary to ensure a fair and reasonable representation of the Company's O&M costs. Adjusting only this one item in isolation will not result in just and reasonable rates.

523. For these reasons, the OAG's recommendation to adjust the 2015 Step revenue requirement to reflect the change in the nuclear refueling outage expenses in 2015 is not warranted.

Xcel Exception to the ALJ Report

The Company stated it believes the ALJ appropriately concluded that nuclear refueling outage costs are O&M expenses that are not subject to adjustment in a multi-year rate plan pursuant to the Commission’s Multiyear Rate Plan Order

OAG Exception to the ALJ Report

The OAG stated it takes exception to the ALJ's recommendation that the Commission ignore the $5.5 million reduction in nuclear refueling expenses in the 2015 step year.

The OAG argued that the ALJ's conclusion that the expenses should not be updated because they are "not capital-related expenses" is misplaced. As a threshold matter, the ALJ incorrectly stated that step year adjustments are limited to capital-related expenses. In fact, in its MYRP Order, the Commission indicated that the types of costs that should be updated were both "costs related to specific, clearly identified capital projects" *and* "appropriate non-capital costs."

Further, the fact that Xcel earns a return on the expenses would further compound the unreasonable impact of failing to make an adjustment. Not only would Xcel be recovering millions in amortized expenses that do not exist; Xcel would also be earning a return on expenses that do not exist. Because of these differences, nuclear refueling expenses are "appropriate non-capital costs" that should be updated for a step-year.

The decision about whether to make an adjustment for a particular expense should be a fact based inquiry; if an expense is either related to specific capital projects or is an "appropriate" non-capital cost, then there should be an adjustment for a step year. Conducting that inquiry for nuclear refueling expenses indicates that the expenses should be adjusted for the 2015 step in this case.

Accordingly, the OAG takes exception to Findings 520, 521, 522, and 523.

Staff Analysis

The Order in the 12-587 docket that established the criteria for a multiyear rate plan allows for the recovery of appropriate non-capital costs. Staffs understanding of that record is the appropriate non-capital costs are those that are directly related to the capital costs which are proposed to be included in the MYRP. The nuclear refueling outage costs are normal O&M expenses for Xcel and are not related to the 2015 step capital additions.

In general, it seems appropriate to adjust the test year for known and measurable changes such as those at issue here. However, that does not appear to be the intent of the Commission in the 12-587 docket. Therefore, Staff believes that no adjustment is required in this instance.

Decision Alternatives

Nuclear Refueling Outage Cost Amortization (2015 Step)

1. Determine that no adjustment is required in the 2015 step for the $5.5 million reduction in nuclear refueling outage cost in 2015. (ALJ, Xcel, DOC)

2. Determine that the 2015 step should include the $5.5 million reduction in nuclear refueling outage cost in 2015. (OAG)

(Note: The decision alternatives for this item correspond to alternative VII, C (1 and 2) on p. 41 of the deliberation outline.)

MYRP: Rate Moderation Proposal – DOE Settlement Funds (2015 Step)

PUC Staff: Jerry Dasinger

Xcel

Clark Direct p 28 – 29
Clark Rebuttal p36 – 42
Robinson Direct p33-34
Robinson Rebuttal p13-19

In its filing Xcel proposed to use the settlement funds received from the DOE to reduce its overall revenue deficiency for 2015. The Company stated that in its last triennial study of nuclear decommissioning costs submitted in November 2011 in Docket No. E-002/M-11-939, the Commission approved an annual nuclear decommissioning accrual amount of $14.2 million and its proposal to fund the accrual using DOE settlement payments. Xcel proposed to continue funding the annual decommissioning accrual using the DOE settlement payments. In this case the Company proposed to use the DOE funds received in 2013 and 2014 in excess of the annual decommissioning accrual amount (totaling approximately $35.8 million) to reduce the 2015 revenue requirement.

According to the Company, these proposals will enable more moderate and predictable year-to-year rate increases for its customers by offsetting the immediate impacts related to the Company's anticipated capital additions. In addition, its rate moderation proposal will have impacts beyond the two-year period of its multi-year rate plan.

DOE Refund Accrual[39]

Minnesota Jurisdictional	Received 2013 for 2014 Decommissioning	Received 2014 for 2015 Decommissioning
DOE Refund - MN Retail	$ 31,810,998	$ 32,404,749
Decommissioning Accrual	$ 14,189,132	$ 14,189,132
Excess Funding	$ 17,621,866	$ 18,215,617
Total DOE Funding in Excess of Accrual		$ 35,837,483

Xcel[40] agreed that the Department's recommendation to make an adjustment (reduction) of approximately $10 million to the available DOE funds is appropriate to accurately account for the total amount available for rate moderation.[41]The funding in excess of the accrual after the reduction is $25,734,695.

The Commercial Group proposed applying the DOE refunds to the 2014 revenue deficiency as well as to 2015 rates, or apply it solely to 2014 rates if the Commission rejects a Step increase. The Company stated that if the DOE refunds were applied to both 2014 and 2014 then $17,622,000 would be applied to 2014 and $8,113,000 to 2015. The Company stated that the determination of the most appropriate application of rate moderation tools depends on the resolution of the broader proposals and issues in this case.

Xcel stated that the Office of the Attorney General, Antitrust and Utilities Division (OAG) appears to argue that rate moderation is not beneficial to customers because it does not offer an actual reduction in the rate increase. The Company disagreed with these recommendations for two reasons. The Company stated it believes that rate moderation tools can be utilized to provide more predictable year-over-year rates, enhance regulatory efficiency, and reduce the impacts of its current investment cycle on its customers.

Department of Commerce

Campbell Direct p 79 -87
Campbell Surrebuttal p 65 - 69

The Department stated that the first and second DOE settlement payments were refunded to the Company's customers, largely due to the fact that the decommissioning funding was at that time considered to be overfunded. Also, the third DOE settlement payment was used for decommissioning purposes since the decommissioning fund was no longer considered overfunded, and resulted in an offset to the decommissioning accrual of $14,189,132 as

---

[39] Table from Robinson Direct p33
[40] Clark Rebuttal p38
[41] The reduction is shown on Robinson Rebuttal Exhibit___(JCR-2), Schedule 4

determined in the Commission's December 4, 2012 Order in Docket No. E002/M-11-939. The Company's next decommissioning study is due October 1, 2014 for the period 2015 to 2017.

The Department noted that the Company stated it will receive DOE payments in 2013 and 2014 that will exceed the Company's nuclear decommissioning accrual requirements through 2015. The Company indicated that approximately $35.8 million of that amount exceeds the Company's decommissioning requirements in 2014 and 2015. Thus, Xcel proposed to use this amount as a rate moderation tool, to offset the Company's 2015 step.

The Department stated that the estimated 2014 DOE refund for the Minnesota retail amount of $32,404,749 has changed. According the Company's response to DOC Information Request No. 1180 regarding changes not yet included in revenue requirements, the Company indicated that the DOE refund for the Minnesota retail jurisdiction is now expected to be $22,301,961, or approximately $10 million lower than the original estimate.

The $17,621,866 amount of DOE funding in excess of decommissioning accrual for 2014 will not change; however, the DOE funding in excess of decommissioning accrual for 2015 will change to $8,112,829. The total of the 2014 and 2015 DOE funding in excess of decommissioning accrual will be $25,734,695 instead of the $35,837,483.

The Department stated that the Company has not provided information to support their change in the DOE refund estimate in response to Department Information Request No. 1180. However, it is anticipated that the Company will provide information to support their change in the DOE refund estimate in their rebuttal testimony.

The Department[42] questioned whether it is a good idea to use DOE settlements funds that currently exceed the nuclear decommission accrual for this rate case as a rate mitigation measure. It has concerns about using this approach instead of keeping these funds for future decommissioning costs. However, since the DOE settlements amounts used by the Company for the rate mitigation in 2015 step are in excess of the currently approved decommissioning accrual, the Department stated it would not oppose using the DOE funding in excess of the current decommissioning accrual at this time, for purposes of this rate case. In general however, the Department recommended that future DOE settlement amounts be used to offset nuclear decommissioning accruals, since that is the purposes of these DOE settlement amounts.

According to the Department the Company did not provide additional information to support the lower DOE expected refund which reduced the DOE excess funds from $35.837 million to the $25.735. Schedule 4 of Robinson Rebuttal Testimony shows the mathematical calculations of the revised DOE refund amount less the decommission accrual to calculate the excess funding. The Department stated this schedule does not support the DOE amount itself being $10.1 million lower. Xcel did not provide any other information in its rebuttal testimonies to support the lower amount.

[42] Campbell Direct p90

The Department believes the Company has a basic formula worked out with DOE via their settlement to determine the refund amount for each year, so it would be expected that the Company would document and use the formula to show why the DOE payment is expected to be lower. It is not clear why Xcel simply has not shown the basis for their expectation that the DOE payment will be reduced and that it will be reduced by the specific sum of $10.1 million. The Department concluded that the $35 million excess DOE funds rather than the $25 million excess DOE funds has been supported in this proceeding.

The Department stated that due to lack of explanation or other support by the Company it cannot accept the Company's revised DOE payment which results in reducing the excess DOE funds from the $35.837million to $25.735 million for purposes of the 2015 Step. Since the Company initially had reflected the $35.837 million in their 2015 Step, but has not supported the revised $25.735 million in DOE excess funds for 2015, the Department recommended the use of the $35.837 million DOE excess funds be used by the Commission for either the 50/30/20 percent with DOE or the 50/40/10 percent with DOE recommendation for rate mitigation.

Campbell opening statement: I also agree that the correct placeholder for DOE funds is now $25.737 million, since the Company provided support for the $10.1 million lower DOE payment in the Second Supplemental Response to DOC information request no. 1180, as discussed by Xcel witness Lisa Perkett in her opening statement[43] (this amount will be trued-up to actual DOE funds, in compliance with Xcel's requirements to return all DOE refunds to ratepayers). This adjustment results in a net $12.633 million increase in revenue in 2015.

OAG

Lindell Direct p 11-13

NSP proposed to reduce its requested increase in 2014 and 2015 with changes to its depreciation reserve amortization and the use of Department of Energy ("DOE") refunds. The OAG stated that the DOE refunds were to be refunded to ratepayers after applying some of the refund amount to fund decommissioning costs for 2014 and 2015.

The OAG argued that NSP's rate moderation proposal does not actually moderate rates for its customers. NSP does not offer any real savings to its customers with its moderation proposal. Instead NSP, in an attempt to make its rate increase request appear more reasonable, simply shifts cost recovery into the future or diverts customer refunds to lower its requested increase in this case.

Similarly, the use of DOE refunds to lower rates in this case does not produce any real savings to ratepayers. The DOE refunds belong to ratepayers regardless of what mechanism is used to return that money to them. If DOE refunds were not used to reduce the revenue requirement in

[43] Hearing Exhibit 130

this case, they would be refunded to customers when NSP received the money from the DOE. NSP's proposal is to retain the refunds and thereby lower the revenue requirement.

The OAG recommended that the Commission carefully consider whether NSP's rate moderation proposal is reasonable and in the public interest. While reducing the current rate increase seems attractive upon first impression, in reality there is no cost savings for ratepayers. NSP's so-called rate moderation proposal, that shifts cost recovery forward or utilizes refunds that customers would have received anyway is not providing any ratepayer benefit. Rate moderation should be real rather than illusory as NSP has proposed.

Commercial Group

Chriss Direct p 12

The Commercial Group stated that the Commission should approve the use of excess DOE payments for rate increase moderation, however, instead of assigning the entire amount to the 2015 step increase as proposed, the Commission should approve the use of the funds received in 2013, approximately $17.6 million, to reduce any approved rate change for the 2014 test year, and funds received in 2014, approximately $18.2 million, for a 2015 step increase, if approved by the Commission. If the Commission does not approve the use of a step increase, the entire amount of approximately $35.8 million should be used to offset any approved rate change for the 2014 test year.

ALJ Report

Findings 620-632

631. If the Commission decides some rate moderation is necessary, the Administrative Law Judge recommends that the Commission use the excess DOE settlement funds from 2013 and 2014 to reduce the level of rate increases. The Administrative Law Judge makes no recommendation, however, regarding whether the funds should be used as an offset only in 2015 as suggested by the Company or spread between 2014 and 2015 as suggested by the Commercial Group. That determination will depend upon the final revenue deficiencies for those two years.

Xcel Exceptions to the ALJ Report

With respect to the use of DOE credits, we concur with the ALJ's recommendation that this pool of funds should be used for rate moderation purposes.143 Although the ALJ made no recommendation with respect to the application of the DOE credits, the Company continues to advocate for the application of the DOE credits to moderate the rate increase for the 2015 Step.

Staff Analysis

The DOE was required by contract to take spent nuclear fuel beginning January 31, 1998. When it did not do this, Xcel incurred additional costs to store spent fuel at its nuclear plants. These additional costs have been charged to and paid by ratepayers in rates since that time.

Xcel reached a Settlement with the DOE to recover damages. The nuclear spent fuel storage damages qualifying for compensation by the DOE include the following cost categories: a) any additional pool storage and other plant modifications; b) dry cask storage and costs directly related to such storage (e.g. internal labor, and overhead, operation and maintenance, training and security); and c) additional property taxes resulting from the on-site dry cask storage or other plant modifications.

The settlement payments received by Xcel from the DOE are a reimbursement of the costs paid by Xcel's ratepayers. The settlement payments are ratepayer funds.

The amounts proposed by Xcel to be used for rate moderation are funds that would be refunded to ratepayers anyway. This is simply a matter as to whether the refund is in the form lower rates or a credit to their bill.

The 2014 DOE payment was received by Xcel on December 18, 2014 as shown in the January 12, 2015 compliance filing in Docket E-002/M-11-807. The actual receipt was $32,761,329 in total with $24,411,103 allocated to the Minnesota jurisdiction.

This amount exceeds the decommissioning accrual of $14,189,132 by $10,221,971. If the Commission approves using the DOE excess payments for rate moderation then $10,221,971 should be used rather than the $8,112,829 found in the Company and Department testimony.

Decision Alternatives

MYRP: Rate Moderation Proposal – DOE Settlement Funds (2015 Step)

1. Allow Xcel to use the excess of the 2013 and 2014 DOE settlement payments over the 2013 and 2014 decommissioning accruals of $27,843,837 to moderate the rate increase for the 2015 step. (Xcel, DOC)

2. Require Xcel to use the excess of the 2013 DOE settlement payment over the 2013 decommissioning accrual of $17,621,866 to moderate the rate increase for the 2014 test year and use the excess of the 2014 DOE settlement payment over the 2014 decommissioning accrual of $10,221,971 to moderate the rate increase of the 2015 step. (Commercial Group)

3. Do not allow Xcel to use any of the DOE settlement funds to moderate it rate increases. (OAG)

(Note: The decision alternatives for this item correspond to alternative VII, D (1 through 3) on p. 42 of the deliberation outline.)

CWIP/AFUDC

PUC Staff: Jerry Dasinger

Xcel

Perkett Direct pp. 51-63
Perkett Rebuttal pp. 14-38
Perkett Opening Statement pp. 2-3
Tyson Rebuttal pp. 11-15
Guest Direct pp. 2-11

Xcel stated that CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use. AFUDC is used to account for the cost of financing during construction. 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.

According to Xcel,[44] jurisdictions (like Minnesota) that allow CWIP in rate base also have a revenue requirement offset of AFUDC incurred in the year, which effectively eliminates the cost of financing construction from the revenue requirement during the construction period. This method allows for a small revenue requirement on the amount of CWIP that does not accrue AFUDC.

There are there exceptions to the commission's general practice for handling CWIP and AFUDC. There is no AFUDC offset:
1) where the Commission authorizes a current return for the project (e.g. transmission and renewable energy projects); and
2) for projects that are low cost (less than $25,000) and short-term (less than 30 days).

The Company stated that the AFUDC rate 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. As required by the FERC formula, the short-term debt rate is applied to the CWIP balance up to the level of short-term debt outstanding. The remaining CWIP balance in excess of outstanding short-term debt receives a rate that is weighted proportionately to the long-term debt, preferred stock (if any), and common equity in the utility's capital structure.

[44] Perkett Direct pp. 51-63

The FERC AFUDC rate is used to offset the carrying cost of the CWIP in the test year by adding the amount of AFUDC (AFUDC rate times the average CWIP balance per month) to net operating income on the income statement. In this current rate case, the $67.2 million of AFUDC was calculated for 2014, total electric and common utility. The jurisdictional portion, $58.1 million, is added to net income in the test year (thus lowering the revenue requirement). Essentially, the AFUDC offset eliminates the carrying costs associated with CWIP in the current revenue requirement. AFUDC is added to construction and eventually the cost of plant. Through depreciation expense, the cost of the plant asset, including the capital cost of funding construction (AFUDC), is recovered. The combination of CWIP in rate base, adding AFUDC to net operating income (the AFUDC offset), and combined with the accumulation and capitalization of AFUDC results in the deferral of construction period financing costs during the construction period. These deferred investment costs are recovered over the useful life of the asset through the recording of book depreciation expense on the total asset investment, including AFUDC recorded during the construction phase.

According to the Company, all CWIP is placed in rate base. There has been no exclusion of less-costly, short-term projects from rate base because such projects are quickly placed into service and are providing service to customers at the time general rates are in effect. More specifically, the policy in Minnesota is to include "short-term" projects in rate base without an AFUDC offset. Because there is no AFUDC offset, there is also no accumulation and capitalization of AFUDC for "short term" projects. "Short-term" projects have been defined by the Commission as projects that will be completed in less than 30 days, or projects that will cost less than $10,000. Under the Company's Uniform Policy on AFUDC, the threshold for including capitalized AFUDC has, with the passage of time, increased from $10,000 to $25,000.

The Company[45] stated that the capitalization of AFUDC reflects the financial need for a return on funds that are used during the construction time period. Xcel argued that the financial need for a return is not limited to external funding. Rather, it applies to the Company's entire investment, including internally generated funds used for capital expenditures and capital investment. If a return is not provided on internally-generated funds, then those funds are, in effect, being provided by NSPM's fixed income and equity investors without any compensation for the period of construction.

The Company stated that shareholders have made substantial reinvestments into NSPM. It would not be reasonable for shareholders to earn no return while portions of their reinvestment were used to fund construction. Further, the size of a project has no significance to the financial requirement for a return on the use of funds during the period of construction.

Xcel argued that the FERC approved AFUDC formula does not provide a return to the company in excess of its cost of financing its capital investments. The FERC approved AFUDC formula first applies the Company's outstanding Short Term Debt (STD) to the CWIP balance and thereafter applies the Company's blended cost of Long Term Debt (LTD) and equity to the CWIP balance. This approach prevents recovery in excess of the Company's overall cost of

[45] Tyson Rebuttal p. 12

capital because STD (the least expensive source of capital) is fully applied before the costs of the other sources of capital are considered.

The Company does not separately allocate funds resulting from LTD and equity when it finances capital assets. The Company initially uses STD and internally generated funds to finance construction. Thereafter, the Company applies its long term sources of capital to repay STD and to meet all of its other financial needs, including financing for capital projects.

Both LTD and equity capital are sources of long term capital, which are used to finance long term assets. Xcel stated it is necessary for it to maintain a balance between the amounts of LTD and equity in its capital structure in order to maintain its credit quality. That balance must be maintained as it finances long term assets. As a result, it does not assign separate sources of long term capital (LTD or equity) to specific long term assets. Further, a claim that it is doing so or should be doing so would be in direct conflict with how it needs to manage its sources of long term capital in order to achieve its targeted capital structure proportions.

James Quest, the former Chief Accountant at FERC provided the following testimony:

He stated he believes the company is calculating its AFUDC rates in a manner consistent with FERC rules. Further that the Company’s calculation of its AFUDC rates properly considers short term debt consistent with FERC's AFUDC rate formulas?

In the Company’s 2013 rate case, testimony of the Office of Attorney General stated that the FERC AFUDC rate formula “assumes that the lowest cost of financing – short-term debt – is used first to finance projects, then if construction costs are higher than the level of short-term debt, the next level of financing – long-term – debt is used. If the construction costs exceed the level of all outstanding debt then equity financing is used.”

Mr. Quest stated that this interpretation of the FERC AFUDC rate formulas is not correct. The FERC AFUDC rate formulas assume that short-term debt is the first source of construction funding, and that construction funding not met by short-term debt is provided proportionally from long term debt, preferred stock (if any), and common equity based on their respective permanent capital ratios. Thus, long-term debt is not exhausted before preferred stock and common equity are considered sources of capital for calculating the AFUDC rate.

Conclusion: The FERC AFUDC rate formulas contained in Electric Plant Instruction No. 3(17) assume short-term debt is the first source of construction funds and that construction funding requirements not met by short-term debt are provided proportionally from long-term debt, preferred stock and common equity. The Company’s calculations of its AFUDC rates used to determine the CWIP AFUDC offset in this proceeding comply with the FERC AFUDC rate formulas and Commission Order Nos. 561 and 561-A. The Company's accounting for AFUDC follows FERC accounting requirements.

Xcel[46] argued that the recommendations to remove CWIP from rate base do not consider all of the cost of service changes that need to be made to effectuate such a change. If CWIP is removed from rate base, the reason for the AFUDC offset is also removed and net income would not be reduced by the amount of accumulated deferred AFUDC. To do so would double count the adjustment. Both the OAG and the Commercial Group ignore the connection between these two items. In addition, neither of them recommends removal of short term debt in the rate of return calculation. Because the AFUDC calculation assumes all short term debt is consumed first, and only after that does it move to the weighted cost of long term capital, the AFDUC rate is over weighted with short term debt, compared to the Company's actual weighted average cost of capital. The only way to avoid double counting of short term debt costs (which are the lowest cost of financing) is to remove this item from the capital structure. This is how the FERC, which does not typically allow CWIP in rate base, calculates the overall revenue requirement.

The OAG asserted that the Minnesota ratemaking process is contrary to FERC rules. In its Direct the OAG states that FERC ratemaking requires AFUDC to not be accumulated if CWIP is placed into rate base, and that in Minnesota CWIP is placed into rate base while AFUDC is allowed to accumulate. The OAG also stated that FERC limits CWIP placed in rate base to 50 percent. The Company argued that the OAG is mixing situations by assuming that the FERC allowance for a current return on CWIP is the same as the Minnesota process where a current return is not allowed and instead the current AFUDC return is deferred until the asset is in service. When either FERC or Minnesota allows CWIP in rate base (whether at 50 percent or 100 percent) for the purpose of allowing a current return, it is without an AFUDC offset. Since a current return is allowed, deferring AFUDC would double count the capital costs incurred during construction. Consequently, both FERC and Minnesota do not allow accumulation of AFUDC when projects are placed in CWIP without an AFUDC offset.

The OAG proposed removing CWIP and AFUDC from ratemaking but would allow AFUDC to accumulate and be deferred for later recovery over the life of the asset. The OAG states (Lindell Direct page 24) that doing so "is consistent with FERC requirements." The OAG does not, however, comply with FERC's requirement that short-term debt be excluded from the capital structure. The three pieces go hand in hand when doing ratemaking under the FERC methodology.

The OAG asserted that removing CWIP and the AFUDC offset from ratemaking would have only a small impact on the revenue requirement. The Company responded that if the only change were to remove CWIP and the AFUDC offset from ratemaking, then the 2014 revenue requirement would decrease and the 2015 revenue requirement would increase as indicated by the OAG. However, as explained in its revised Response to IRs DOC-138 and DOC-139, to be consistent with FERC requirements, such a change in ratemaking would also require the removal of short term debt from the capital structure.

Including short-term debt in the capital structure without including CWIP in rate base implies that CWIP is financed pro-rata by all sources of capital. However, as the FERC AFUDC rate

[46] Perkett Rebuttal pp. 15-16

recognizes, the capital used during the construction period relies first on short-term debt and relies on long term debt and equity only after short-term debt is exhausted. Therefore, if CWIP is excluded from rate base, the short-term debt also should be excluded from the capital structure.

The impact of removing CWIP, the AFDUC offset, and removing the cost of short term debt from the capital structure would increase the revenue requirement in 2014 by $8.5 million, and would increase the revenue requirement in 2015 by $12.4 million.

Xcel argued that the FERC required AFUDC rate should not be replaced as the OAG proposed unless the Commission finds good cause for not complying with the uniform system of accounts. This would create an inconsistency in how AFUDC is recorded for accounting purposes and how it is treated for ratemaking purposes, resulting in ongoing financial losses. There is no support for not allowing the Company to recover its true cost of capital. Second, FERC's AFUDC rate correctly reflects the use of short term debt to fund construction and that once the available short term debt is exhausted then all long term capital (both debt and equity) is applied to fund the investment. The Company's capital structure is specifically designed to provide the appropriate mix of short term, long term and equity capital.[47]

In response to the OAG proposal to limit AFUDC to projects costing more than $25 million, the Company stated if CWIP and AFUDC are removed from rate making and AFUDC is only deferred for recovery on projects costing more than $25 million, it would suffer a permanent disallowance of all capital costs during construction for those projects. The consequence of the OAG's proposal is that the Company would under-earn its allowed cost of equity. Xcel estimated that approximately 62 percent of CWIP investment in the test year is associated with projects less than $25 million. This would represent a denial of any cost of capital associated with financing approximately $441 million in CWIP. This is inconsistent with any regulatory structure intended to allow a utility a reasonable opportunity to earn its authorized return on equity.

The Company first uses short-term debt to finance construction and once that is exhausted it uses its mix of long-term debt and equity to provide the necessary capital. Because the Company is entitled to recover its cost of capital in rates this proposal should be rejected.

In response to the OAG regarding suspended or cancelled projects, Xcel[48] stated FERC rules prevent accruing additional AFUDC on expenditures made during project suspensions and after project terminations. However, it does not support the write off of AFUDC taken up to the time of abandonment. The investment costs accumulated during active construction, up to the date of abandonment, will continue until recovered.

The allowance of AFUDC capitalization during the period of active construction is explained in FERC Accounting Release No. 5 (AR-5). AR-5 prohibits the capitalization of AFUDC during

[47] Perkett Rebuttal p. 28
[48] Perkett Rebuttal pp. 32-34

periods of interrupted construction, unless the company can justify the interruption as being reasonable under the circumstances.

The OAG recommended disallowance of $12.8 million in accumulated AFUDC related to Prairie Island, asserting that AFUDC cannot be recovered for cancelled projects based on FERC requirements. The Company argued that accumulated AFUDC existing at the time of the cancellation is recoverable for the entire period during which the project remained prudent.

Xcel[49] stated it has a Company policy that implements the FERC requirements for interrupted and cancelled projects. (See Exhibit_LHP-2), Schedule 9.) The Sherco Unit 3 restoration project and the Monticello LCM/EPU project would not justify a suspension of AFUDC under that policy. Sherco Unit 3 construction that was completed, but not in-service when the unit failed, was moved from CWIP shortly after the incident occurred and placed in Hold for Future Use (HFU) status as the assets were ready for service. These assets remained in HFU while the repairs were made. No AFUDC is taken on assets in HFU.

For the Monticello LCM/EPU, this project was not considered to be in a suspended status either. As assets within this large project were in use, these assets were moved to plant in service, thus AFUDC was stopped appropriately. A long construction period does not equate to a suspended project. The FERC notes in EPI 3 that "[w]hen a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as Electric Plant in Service and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service."

Xcel[50] argued that the process used for addressing capital costs during construction has been uniformly applied for more than 40 years. The OAG and the Commercial Group have not provided a reasonable basis for changing that process. Additionally, if the Commission were to replace the current method with the FERC method, its revenue requirement would increase. The Company is in compliance with all FERC requirements for AFUDC, including the calculation of the AFUDC rate and the treatment of AFUDC during interruptions and for cancelled projects.

OAG

Lindell Direct pp. 16-29
Lindell Surrebuttal pp. 1-17

The OAG stated that NSP's high cost of service can be partly attributable to its approach to accrue and capitalize high cost financing as AFUDC and to include CWIP in rate base.

---

[49] Perkett Rebuttal p. 36
[50] Perkett Rebuttal p. 37

According to the OAG,[51] NSP did not demonstrate that it had met the FERC requirements as ordered by the Commission in docket 2-961. NSP's witnesses Ms. Perkett and Mr. James Guest addressed the AFUDC rate and the dollar level of individual CWIP projects that NSP accrues AFUDC on. NSP did not address FERC's limitation to only include 50% of CWIP in rate base. NSP also did not address FERC's requirement that CWIP projects that are interrupted or delayed shall not accrue AFUDC during the period of interruption.

The OAG[52] stated that based on its review of NSP's testimony and the treatise of Robert Hahne and Gregory Aliff, it concluded that NSP's formulaic calculation of AFUDC is compliant with FERC's requirements. However, FERC established a standardized method to determine the maximum allowable AFUDC accrual rate. NSP's calculation of AFUDC maximizes the rate for financing NSP's construction projects which is not beneficial to ratepayers.

NSP witness, Ms. Lisa Perkett, states that its AFUDC rate is beneficial to customers. According to Ms. Perkett, the benefit of AFUDC is that the income statement includes AFUDC which increases net income and thereby reduces the revenue deficiency.

The OAG[53] argued that NSP's treatment of CWIP and AFUDC is not beneficial to ratepayers. Including CWIP in rate base and AFUDC in income does not result in lower rates for NSP's customers. NSP's approach of including CWIP in rate base allows NSP's investors to earn a return on plant that is not used and useful and in some circumstances will not be completed. If projects are canceled NSP continues to earn a return on the project. Under NSP's approach, the offset in the income statement defers a portion of the return for the future when the CWIP projects are completed and depreciation begins.

AFUDC is intended to recognize the need for financing large construction projects for a utility. Applying an AFUDC rate to costs incurred for uncompleted projects and accruing the financing cost as part of CWIP projects recognizes that the project will need external financing. The OAG argued that external financing is only needed when cash generated from operations is insufficient to finance the projects. NSP improperly accrues AFUDC on virtually all CWIP projects despite the substantial level of internally generated cash from operations that are available to finance CWIP projects.

Applying FERC's formulaic application of AFUDC for accrual on all CWIP projects fails to recognize that not all CWIP projects require external financing. The OAG recommended that CWIP and AFUDC be excluded from setting rates. Excluding all CWIP from rate base and AFUDC from the income statement results in a de minimis impact on NSP's revenue requirement and is consistent with FERC requirements.[54]

According to NSP's response to the Department of Commerce ("DOC"), the test year revenue requirement impact removing CWIP and AFUDC from the test year rate base and income

[51] Lindell Direct p. 19
[52] Lindell Direct p. 21
[53] Lindell Direct p. 22
[54] Lindell Direct pp. 23-24

statement, results in a reduction of $3.8 million from the 2014 revenue requirement and an increase of 0.9 million for the 2015 revenue requirement.

NSP provided a revised response to DOC IRs stating it failed to adjust the rate of return to exclude low cost short-term debt in its cost of capital which NSP claims is consistent with FERC's ratemaking practice. The argument is that short-term debt used to calculate AFUDC results in excluding short-term debt from the cost of capital which increases the overall cost of capital used to calculate a return on rate base. With the short-term debt adjustment, NSP claims a substantially higher rate of return and revenue requirement. The OAG[55] stated it does not accept NSP's revision explanation. Even if NSP's revision to DOC IRs 138 and 139 correctly applies FERC's ratemaking treatment, that approach is not required for Minnesota ratemaking.

The OAG expressed concerns that that NSP did not stop accruing AFUDC on certain projects. NSP has started and then delayed several projects for which AFUDC accrual should have been suspended. Three prime examples are Sherco 3, Monticello LCM/EPU project and the Prairie Island EPU.

The OAG also had other concerns regarding NSP's inclusion of CWIP and AFUDC in its 2014 test year. Based on NSP's recent history, it is likely that some of these projects will be canceled or delayed. If the projects are delayed or canceled then NSP's test year accrual of AFUDC would not be accurate. Another concern is that CWIP in rate base is contrary to the cost recovery requirement that capital investments be "used and useful" in the provision of utility service.

The OAG argued that NSP's AFUDC rate is not reasonable. It recommended that equity not be used in the calculation of an AFUDC rate. NSP's short-term debt rate of 0.353% and long-term debt rate of 4.88% shown on NSP's witness Mr. Guest's Schedule should be used to calculate NSP's AFUDC rate. A blended short-term and long-term rate weighted at 50% each produces a rate of 2.62%.

The OAG recommended the following for CWIP and AFUDC:

- CWIP should not be included in rate base;
- Only CWIP projects in excess of $25 million should accrue AFUDC;
- CWIP projects that are delayed or interrupted should not have AFUDC accruing during the period of interruption; and
- The AFUDC rate for eligible projects should be 2.62%.

The OAG[56]stated the only difference between the OAG and NSP regarding FERC accounting requirements is whether the computed AFUDC rate should be the maximum allowed. FERC does not mandate that the maximum AFUDC rate be used. It also allows the use of a lower AFUDC rate without special authorization from FERC.

[55] Lindell Direct pp. 24-25
[56] Lindell Surrebuttal pp. 3-5

NSP and the OAG differ on their AFUDC rate. NSP's recommended AFUDC rate includes the capital components, including equity, that are included in NSP's overall costs of capital. NSP's method results in excessive returns at the expense of ratepayers. Instead, the OAG recommends a 2.62% AFUDC rate, which reflects a weighted cost of short-term debt and long-term debt and does not include equity. Equity, as distinct from borrowed funds, should only be considered in situations where the cost of CWIP projects requires the use of addition funds other than debt.

According to Xcel, the OAG's recommendation would conflict with the USOA and would be inconsistent with how AFUDC is recorded for accounting and ratemaking purposes. The OAG[57]stated that is incorrect. Its recommended AFUDC rate complies with FERC accounting requirements. FERC's Electric Plant Instruction 3(A)(17) permits a lower rate than the maximum allowed under the formula.

For businesses in general, there is no need to externally finance capital projects if internally generated cash from operations is sufficient to finance them. Non-regulated businesses do not earn a return on an investment until the investment is productive, or in regulatory terms, "used and useful." NSP's (Tyson) statement that internally generated cash should earn a return is also contrary to how rates are set. Cash is not included in the rate base except to the extent cash is used to finance day-to-day operations. This rate base component is called cash working capital and is calculated by measuring the timing and amounts of revenues and expenses that are used to finance day-to-day operations. The OAG argued that its recommended use of a blended short term and long-term cost of debt incorporates FERC's AFUDC requirement that allows a "reasonable rate on other funds."

The OAG[58] stated that NSP's argument that using debt to compute the AFUDC rate results in an increase in the cost of capital or rate of return based on FERC ratemaking requirements is incorrect. NSP claims that removing CWIP and AFUDC from the calculation of the revenue requirement would result in removing short-term debt from the calculation of the weighted cost of capital and thereby increase the rate of return. NSP's attempt to link the exclusion of short-term debt from the weighted cost of capital to the OAG's recommendations for CWIP and AFUDC is not supported by FERC's ratemaking requirements. NSP correctly explains that FERC rules establishing the computation for the rate of return do not include short-term debt. FERC rules exclude short-term debt from the rate of return calculation regardless of how AFUDC is calculated.

The OAG stated its recommendations regarding CWIP and AFUDC do not upset 40 years of ratemaking history because Rate setting has always been an evolving mechanism. The approach of including CWIP and AFUDC to set rates has had very little consideration in previous rate cases. This is likely due to the more limited level of capital investment by NSP and other Minnesota utilities historically such that it had a less prominent impact on the revenue requirement. The current case highlights the high cost impact of NSP's methodology on ratepayers. The goal of ratemaking is to establish just and reasonable rates. NSP's

---

[57] Lindell Surrebuttal p. 6
[58] Lindell Surrebuttal pp. 9-10

recommendation, to include all CWIP in rate base and include AFUDC in the income statement, does not establish just and reasonable rates in this case.

The OAG disagreed that its recommendation to remove CWIP and the AFUDC offset is unbalanced and non-compliant with FERC's requirements. Rather, NSP's approach produces excessive rates and does not balance the interests of ratepayers and investors. NSP argued that the OAG's recommended methodology results in higher ratepayer costs by $8.5 million in 2014 and $12.4 million in 2015. However, that change in revenue requirement assumes that short-term debt is removed from the calculation of the rate of return to set Minnesota rates. While there is a difference in ratemaking treatment between FERC and Minnesota about whether to use short-term debt as a cost of capital, the difference is not linked to whether CWIP and AFUDC are included in rate base and the income statement, respectively.

The OAG[59] stated that NSP misrepresents the effect of its recommendation to exclude small and medium sized projects (under $25 million) from AFUDC accrual. First, NSP's position appears to be that a full rate of return should be allowed on all CWIP projects so that NSP will not under-earn its cost of equity. The Company's position is contrary to the intent of AFUDC which is to allow for recovery of financing costs and other funds when so used, and is also contrary to the principle that a full rate of return is only allowed on property that is used and useful in the provision of utility service. Furthermore, allowing a full rate of return on all projected construction projects in NSP's 2014 test year allows NSP to earn a return on investments that it may or may not be making.

The OAG recommended that CWIP and AFUDC not be included in rate base and the income statement, respectively, in this case. It also recommended that the Commission establish an AFUDC rate of 2.62 percent and that it only be applied to CWIP projects in excess of $25 million. Finally, as required by FERC USOA, projects that are canceled or delayed should not have AFUDC accrued during delays or when canceled. NSP's approach improperly increases its accounting costs and results in unjust and unreasonable rates. The OAG argued that its recommendations fairly balance the interests of ratepayers and investors.

Commercial Group

Chriss Direct pp. 10-11

According to the Commercial Group, the inclusion of CWIP in rate base charges ratepayers for assets that are not yet used and useful in the provision of electric service. Under the Company's proposal, ratepayers would pay for the assets during a period when they are not receiving benefits from those assets, so the matching principle (i.e. customers bearing costs only when they are receiving a benefit) is violated. In this case, NSPM's customers would pay for an asset that does not provide service – i.e., is not used and useful – during that test year.

[59] Lindell Surrebuttal pp. 13-14

Including CWIP in rate base shifts the risks to ratepayers that are traditionally assumed by utility investors, for which investors are compensated through the rate of return elements once the plant is in service. Additionally, should the Company encounter problems during construction of the plant resulting in stoppage of the construction or non-completion of the project, consumers have no recourse for recovering the money they have paid for the inclusion of CWIP in rate base.

NSPM proposes to include approximately $570 million of CWIP in rate base which constitutes approximately 8.6 percent of the Company's rate base. The inclusion of CWIP in rate base results in a revenue requirement impact of approximately $74 million.

The Commercial Group opposes the inclusion of CWIP in rate base. The Commercial Group argued that if the Commission determines it is necessary to include CWIP in rate base, it should determine that the shift of risk from the Company to ratepayers through the inclusion of CWIP be reflected in the ROE approved in this docket, such that as the level of CWIP is increased, ROE is accordingly reduced.

The Commercial Group recommended that the Commission should closely examine NSPM's proposed revenue increase in light of what appears to be an excessive increase in operating income and return on equity, especially when viewed in light of the Company's risk reducing ratemaking structures described above.

ALJ Report

Findings 524–547

542. The Company has shown that its proposed inclusion of CWIP and AFUDC is consistent with FERC accounting requirements, Minn. Stat. § 2168.16, and longstanding Commission precedent. As explained in more detail below, the OAG has failed to show that any change to the Company's longstanding accounting for CWIP and AFUDC is necessary or reasonable.

543. First, the OAG has not demonstrated that its proposal to exclude CWIP and the AFUDC offset, and instead allow AFUDC to accrue until the plant is placed in service, would result in more reasonable rates. If the OAG's approach were adopted, to be consistent with FERC ratemaking principles, the Commission would also need to exclude short-term debt from the Company's capital structure. The record in this case shows that this approach would increase the 2014 test year revenue requirement by $8.5 million and increase the 2015 Step revenue requirement by $12.4 million.

544. The OAG argued that the Commission does not need to exclude short term debt from the cost of capital even if it excludes CWIP from rate base because FERC's ratemaking principles are not binding on the Commission. This argument, however, fails to recognize that short-term debt generally does not support rate base but rather it is commonly used for temporary financing of construction projects. Because short-term debt is used to fund CWIP, it would not be reasonable to exclude CWIP from rate base but still include short-term financing in the capital

structure. Significantly, the OAG has not identified any state jurisdiction that has taken the OAG's proposed approach to CWIP and cost of capital. Moreover, the OAG's proposal to exclude CWIP from rate base fails to give "due consideration to ... construction work in progress" as required by Minn. Stat. § 2168.16, subd. 6. For these reasons, the Administrative Law Judge concludes that the Company's proposed inclusion of CWIP with an AFUDC offset, except in limited circumstances, is more reasonable and balanced than the OAG's alternative approach.

545. Second, the OAG has not demonstrated a reasonable basis for limiting accrual of AFUDC to projects that exceed $25 million. The OAG's proposal would deny the Company an opportunity to recover its financing costs for approximately 62 percent of its capital projects included in the 2014 test year. The cost of financing these projects is a real cost that the Company incurs. Contrary to the assertion of the OAG, there is no evidence that the Company has sufficient excess revenue to be able to fund 62 percent of its capital projects without external financing. The OAG failed to consider that retail revenues are set at a level to cover the Company's costs of providing service and not set at a level that allows revenue to be used as a replacement for capital. Thus, limiting accrual of AFUDC to projects that exceed $25 million would deny the Company a fair opportunity to recover its financing costs for projects under that amount.

546. Third, the OAG has not demonstrated that it is reasonable to set the AFUDC rate at 2.62 percent, rather than 6.79 percent as proposed by the Company. The Company's proposed rate is calculated in accordance with the FERC formula. The OAG's proposed rate, on the other hand, is the average of the Company's short term and long-term debt rates. The OAG maintained that non-debt sources of financing should only be included in the AFUDC rate if the Company can demonstrate that it actually has used equity to fund particular construction projects. The OAG asserted that the Company has funds available from the rates it collects, including excess interim rates, and does not need equity to fund its capital projects. Here again, the OAG failed to consider that the Company's rates are set to cover its costs. In addition, the OAG also ignores that excess interim rates are refunded with interest. As a result, the Company utilizes equity in addition to debt to finance its capital projects. Finally, it would not be reasonable to adopt the OAG's suggestion that equity should only be included in the AFUDC rate if the Company can clearly trace a particular equity issuance to a specific project because, as the OAG has acknowledged, it is not possible to trace specific funds to a particular construction project.

547. For these reasons, the Administrative Law Judge recommends no change to the Company's treatment of AFUDC and CWIP, which is based on long-standing Commission precedent.

Xcel Exceptions to ALJ Report

In exceptions, Xcel provided comments reiterating its position:

- The Company established that the system of CWIP and AFUDC accounting it has used since 1977 is consistent with the FERC Uniform System of Accounts and with Minnesota Statutes.
- The OAG's proposed adjustments to CWIP and AFUDC accounting are inconsistent with FERC ratemaking principles, novel, and do not result in balanced accounting for these incurred costs.
- The OAG proposed AFUDC rate of 2.62 percent ignores that the Company utilizes both equity and debt to finance capital projects.
- The OAG's proposal to limit accrual of AFUDC to projects that exceed $25 million would deny the Company the ability to recover the very real financing costs for approximately 62 percent of Company projects.

Xcel stated it believes the ALJ reached a reasoned outcome consistent with fundamental ratemaking principles, long-standing Commission precedent, and Minnesota statutes.

Staff Analysis

The question in the 12-961 rate case was whether the Company was making the AFUDC rate calculation according to the FERC requirements. In this case, the Company provided schedules showing its AFUDC rate calculation. No one disputed that Xcel's calculation was made according to the FERC requirements. The OAG argued that Xcel's calculation resulted in the maximum rate and proposed a different rate based only on debt. Xcel's policies and procedures appear to comply with the FERC requirements for AFUDC. Staff agrees with the ALJ that there has not been any reason presented in this case to change the Company's treatment of CWIP and AFUDC.

The ALJ stated that if the OAG's approach to exclude CWIP and the AFUDC offset, and instead allow AFUDC to accrue until the plant is placed in service were adopted, then to be consistent with FERC ratemaking principles, the Commission would also need to exclude short-term debt from the Company's capital structure. Staff believes this is not relevant to this issue because that is a FERC ratemaking principle not a Minnesota ratemaking principle. If CWIP and the AFUDC offset were removed from ratebase, there should not be an adjustment to the rate of return. Further, while short term debt can be used for temporary financing of construction projects, it is normally and frequently used for operating capital depending on the normal cash flow from company operations. Staff also notes that the Company's revenues include a recovery of depreciation expense which is a noncash expense so it is not reasonable to conclude that revenues equal cash flow.

Decision Alternatives

CWIP/AFUDC

1. Determine that Xcel's calculation of the AFUDC rate complies with FERC requirements and that its policies and procedures for AFUDC are reasonable and the Company should be allowed to continue using those policies and procedures. (ALJ, Xcel)

2. Approve the OAG recommendation that CWIP and AFUDC not be included in rate base and the income statement, respectively, in this case; that the AFUDC rate of 2.62 percent be approved and that it only be applied to CWIP projects in excess of $25 million. Finally, as required by FERC USOA, projects that are canceled or delayed should not have AFUDC accrued during delays or when canceled. (OAG)

3. Determine that CWIP should not be included in rate base. (Commercial Group)

4. Determine that if CWIP is included in rate base that the inclusion of CWIP be reflected in the ROE approved in this docket, such that as the level of CWIP is increased, ROE is accordingly reduced. (Commercial Group)

(Note: The decision alternatives for this item correspond to alternative VII, E (1 through 4) on p. 42 of the deliberation outline.)

Return on Nuclear Refueling Outage (NRO) Costs

PUC Staff: Jerry Dasinger

Xcel

Robinson Rebuttal p21 – 25

According to Xcel, the OAG objected to the Company's continued use of the deferral and amortization method for nuclear refueling outage costs, as it believes that a normalization method would be superior. Xcel stated the nuclear outage costs include maintenance expenses that are incurred at the plant during a nuclear refueling outage. These costs exclude nuclear fuel expenses, which are capitalized and amortized by calculating the thermal energy produced in a given month divided by the total thermal energy available while the fuel is in the reactor core. In addition, only expenses that are directly associated with a planned refueling outage are included in deferral and amortization. Expenses for non-refueling outage activities, such as LCM or EPU activities, are not included, nor are costs incurred during unplanned outages.

The Company stated that under the deferral and amortization method, the expenses incurred during an outage are deferred in the month in which they occur and are amortized over the period of time between the expenditures and the next outage for that unit, typically between 18 and 24 months.

Xcel stated it supports the use of the deferral and amortization method for these expenses as a means to promote stability, predictability, and fairness for its customers. First, given that nuclear refueling outage expenses can be substantial, this methodology moderates rate increases by phasing them in over a longer period of time. Second, refueling expenses can vary significantly from year to year depending on the number of outages per year. This methodology also moderates these variations. Third, the deferral and amortization method matches the outage costs to the period during which the benefits from the outage occur.

The deferral and amortization method has been approved by the Commission for ratemaking purposes in the Company's 2008, 2010, and 2012 rate cases.

Xcel argued that it is appropriate to apply a carrying charge to nuclear refueling outage costs because under fundamental ratemaking principals, when the recovery of an expense is delayed, a carrying charge is added to the unamortized amount to reflect the time value of money until the expense is recovered.

OAG

Lindell Direct p 44-47
Lindell Surrebuttal p 24-26

According to the OAG, prior to 2008, NSP recovered nuclear refueling outage (NRO) expenses using normalization or averaging method that considers the average of costs over a number of years to determine a reasonable level of costs for recovery. Starting in 2008, NSP began accounting for NRO expenses using the deferral and amortization expense method.

This changed NSP's accounting method to deferring NRO expenses during nuclear refueling outages and then amortizing those deferred costs between outages. Rather than recognizing the expense in the year that they are incurred, NSP recognizes them over an 18 to 24 month period - the period between outages. In addition, NSP calculates a return on the average unamortized expenses which provides a return or profit on the expense using this accounting method.

The OAG argued that normalization accomplishes essentially the same level of recovery for NRO expenses as the deferral and amortization method except that NSP earns a return on its NRO expenses which increases the level of recovery for these expenses.

From 2008 to 2013, NSP's customers have paid and an additional $16.7 million in excess of NSP's actual NRO expenses, which represents the return that NSP receives as a result of using the deferral and amortization method of accounting. NSP is proposing an additional $4.6 million as a return on NRO expenses for its 2014 test year.

The OAG argued that the deferral and amortization method of accounting result in incentives for NSP to expand the scope of NRO expenses because the higher the level of deferred and unamortized expenses, the higher the return that NSP and its shareholders receive.

The OAG recommended that NSP be allowed to continue the use of the deferral and amortization method of accounting to set rates but no return should be allowed.

In Surrebuttal, the OAG stated that NSP claims that the Commission has consistently denied the OAG's recommendation on cost recovery for NRO expenses. However, NSP does not acknowledge that the OAG's arguments were different in each of NSP's last three cases than they are in this case. NSP also does not explain that the ALJ in NSP's last case recommended adopting, in part, the OAG's position on recovery of NRO expenses.

The OAG stated that in NSP's last rate case (12-961), it objected to the use of a deferral and amortization method of accounting for NRO expenses and supported that recommendation by showing that the normalization method produced essentially the same level of costs for recovery as NSP's proposal using the deferral and amortization method in prior cases. The OAG differed with NSP on the level of recovery in NSP's last case due in large part because NSP was including a profit on the deferred NRO expenses. NSP's proposal was to use its cost of capital to calculate the profit on the unamortized NRO expenses, which had escalated significantly after the deferral and amortization method of accounting was approved. NSP included a return as part of the NRO expense.

In the 12-961 rate case, the ALJ stated in paragraph 617:

> For these same reasons, it continues to be reasonable for the Company to include a carrying charge in this rate case. The Administrative Law Judge agrees with the OAG, however, that rather than using the rate-of-return for the carrying charge rate, a more appropriate rate would be the short-term cost of debt or the prime interest rate. A lower rate is reasonable because the expense is amortized over a relatively short period of time. Accordingly, the Administrative Law Judge recommends that the Company be allowed to impose a carrying charge but the carrying charge should reflect the short term use of the money.

The OAG stated that as this finding by the ALJ demonstrates, NSP has an incentive to increase the scope and level of NRO expenses if it is allowed to earn its full rate of return. The ALJ supported a carrying charge rate that is less than the full rate of return in support of the OAG's concern that a return on deferred expenses provides incentives to increase the scope and level of those deferred expenses. The OAG recommended the NSP not be allowed a carrying charge on NRO expenses.

ALJ Report

Findings 502-513

511. The Commission addressed this same issue in the Company's 2012 rate case. In that case, the OAG also opposed the inclusion of a carrying charge under the deferral and amortization method. The Commission disagreed with the OAG and concluded that "the rate of return is the appropriate time-cost of money in this situation."

512. The issue was also addressed in the 2010 rate case. In that rate case, the Administrative Law Judge concluded that:

> The deferral and amortization method incorporates a carrying charge to reflect the time value of money until the costs are recovered. So long as the practice of including a carrying charge is balanced with payments to ratepayers when costs are deferred, the practice is reasonable.

In its order in the 2010 rate case, the Commission did not address the issue in detail but did adopt the Findings, Conclusions, and Recommendation of the ALJ on the issue.

513. For these same reasons, it continues to be reasonable for the Company to include a carrying charge under the deferral and amortization method of accounting for nuclear refueling outage expenses. Consistent with the Commission's decision in the last rate case, the Administrative Law Judge concludes that the Company should be allowed to include a carrying charge equal to its rate of return.

Xcel Exceptions to the ALJ Report

The Company supported the ALJ's finding stating the ALJs and Commission addressed this precise issue in the Company's 2010 and 2012 rate cases, and concluded that a carrying charge properly reflects the time value of money associated with deferring recovery of these costs. There is no reason to revisit this analysis.

Staff Analysis

In Docket No. E-002/M-07-1489, Xcel requested that it be allowed to change from the direct expense method to the deferral and amortization method of accounting for NRO costs. The Company made the proposal in order to levelize its NRO costs which results in the Company's earnings being less volatile. In that docket, the DOC stated that its analysis showed that the proposed change provided no benefits for ratepayers. The change was proposed to make Xcel's earnings more stable, not to provide any ratepayer benefit.

The fact is that as a result of Xcel including the unamortized costs in rate base, ratepayers are harmed. The refueling expenses were and still are paid around the time of the refueling and the recovery from ratepayers did and still occurs over a period of time. The only thing that changed was the accounting. Simply as a result of the change in accounting, Xcel was able to convert an operating income expense where it was allowed a recovery of the cost to a rate base item for which it not only gets a recovery of the cost, it gets a recovery on the cost like it does for plant in service.

Before the change ratepayers never paid a return on NOR costs. Now they do and ratepayers are harmed as a result. According to the OAG, the extra amount charged ratepayers for 2008 through 2013 was $16.7 million. This extra cost for ratepayers is a rate of return on the unamortized balance of the NOR costs. Xcel refers to it as a carrying charge.

Staff agrees with the OAG that allowing Xcel to earn a rate of return on these costs is not fair to ratepayers. However, the Commission has consistently allowed Xcel to earn a rate of return on these costs.

Decision Alternatives

Rate of Return on Unamortized Nuclear Refueling Outage (NRO) Costs

1. Allow Xcel to include the unamortized NRO costs in rate base and earn the overall allowed rate of return on that balance. (ALJ, Xcel)

2. Allow Xcel (NSP) to continue to use the deferral and amortization method of accounting to set rates but do not allow a return on the unamortized costs. (OAG)

(Note: The decision alternatives for this item correspond to alternative VII, F (1 and 2) on p. 43 of the deliberation outline.)

Nuclear Theoretical Depreciation Reserve

PUC Staff: Jerry Dasinger

Xcel

Perkett Direct pp. 43-51
Perkett Rebuttal pp. 7-14

Xcel[60] stated that a theoretical reserve analysis measures, at one point in time, the actual depreciation reserve compared to the theoretical reserve. The theoretical reserve is the reserve that would exist if all the facts that go into the depreciation calculation that are currently known were known at the time the asset was placed into service. For example, if an asset initially had a 10-year life and the asset has been in service for five years, the depreciation reserve would be 50 percent of the asset cost. If at this point, the life were extended 10 years to a total of 20 years, the theoretical reserve would estimate that 25 percent of asset costs should have been recovered to that point (over five of the total 20-year life of the asset), even though 50 percent of asset costs would actually have been recovered.

The Company argued that a reserve surplus does not necessarily indicate there is an issue that needs to be addressed. The Company will recover 100 percent of the asset cost regardless of the theoretical reserve calculated at any one point in time. The Company stated that for its nuclear assets, like all of its production assets, it uses a remaining life depreciation methodology, which automatically spreads any reserve surplus or deficit evenly over the remaining life of the asset.

The following table shows the results of the Company's analysis as of December 31, 2012.[61]

Nuclear Plant Theoretical Reserve Balance			
Plant	Actual Reserve	Theoretical Reserve	Difference
Monticello	$439,096,433	$515,265,652	$(76,169,219)
Prairie Island	918,791,270	745,151,763	173,639,507
Total	$1,357,887,703	$1,260,417,415	$97,470,288

The primary driver of the reserve surplus for Prairie Island is the fact that between 1994 and 2003, the remaining life for the plant was kept 6.5 years shorter than its approved NRC license life. Due to a change in state law, during that period there was significant uncertainty regarding the Company's ability to store enough dry spent nuclear fuel on-site to support operations until the end of its approved license life. As this situation could have caused early retirement of the

[60] Perkett Direct p. 44
[61] Perkett Direct p. 47

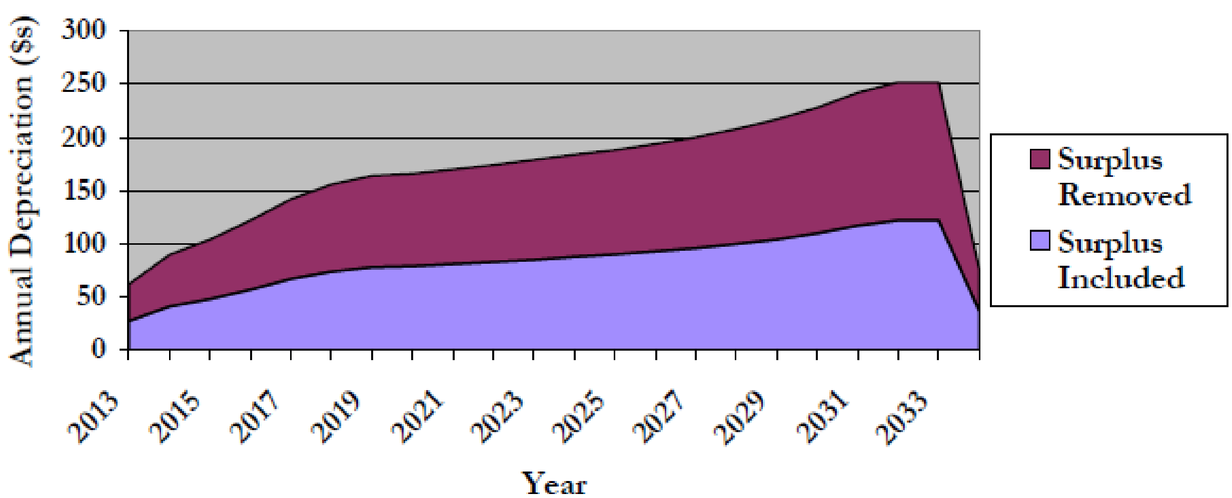
Prairie Island plant, the Company requested, and the Commission approved, that costs be recovered over a shorter period to minimize potential financial risk to the Company. Because the asset costs were being recovered over a shorter period, the accumulated depreciation balance is currently higher than it would otherwise have been.

Xcel stated that because it uses the remaining life depreciation methodology for its nuclear plants, the Prairie Island reserve surplus is automatically spread over the remaining life of the plant, which lowers future depreciation costs. In the case of the reserve deficit for Monticello, the remaining life depreciation methodology automatically spreads the deficit over the remaining life of the plant, which increases future depreciation costs.

The Company stated that the Prairie Island reserve surplus and the Monticello reserve deficit could be netted to calculate an overall nuclear depreciation reserve. Because plants are in the same functional class (nuclear), FERC accounting rules would allow a transfer of some portion of the Prairie Island surplus to offset all or a portion of the Monticello deficit. This would rebalance the theoretical reserves at this point in time, and would decrease depreciation costs for Monticello and increase depreciation costs for Prairie Island going forward.

Future additions do not directly factor into the calculation of the theoretical reserve. According to the Company, due to significant recent and planned investment in nuclear assets, there is a sizeable expected increase in depreciation over the remaining lives of these assets. The Company argued that any reduction in the current reserve due to use of the theoretical reserve surplus would cause an increase in the depreciation to be paid by customers in the future. As an example, Figure 1 below shows the effect over time on depreciation expense if the approximately $174 million theoretical reserve surplus for Prairie Island is removed.

Figure 1



The Company[62] disagreed with XLI that it incorrectly determined the theoretical reserve for its nuclear units. Xcel stated that XLI increased the theoretical reserve by $41.5 million (Minnesota Jurisdiction) by ignoring the need for future capital additions. Second, XLI asserts that the Company incorrectly calculated the theoretical reserve because it did not use vintage data to make that calculation. Using vintage data, XLI increases the theoretical reserve by an additional $122.1 million (Minnesota Jurisdiction).

Xcel argued that changing the theoretical reserve for these units does not change the total amount of depreciation that must be recovered over their remaining lives. There is a finite life for each plant, and all of the dollars collected to date will be needed to retire these plants.

The Company stated it did not consider the need for future capital additions in determining the depreciation expense. The Commission-approved depreciation expense is based solely on existing investments and existing remaining lives. Xcel stated it did, however, consider the need for future capital additions and the overall impacts to current and future customers when calculating the reserve surplus. In other words, the information was used to present a realistic view of the depreciation reserve over the remaining life of each plant.

Xcel[63] argued that to the extent an adjustment to refund the theoretical reserve is made; it should take into account the impacts of both current and future ratepayers. Based on the real need for large capital additions at each plant in the future, the Company determined that including future capital additions as part of determining the level of the existing reserve was a more appropriate balancing of interests.

With each depreciation calculation, the Company is effectively spreading any surplus or shortfall contained in accumulated depreciation over the remaining life of the plant. Thus, the theoretical surplus lowers depreciation expense over the life of the assets.

Xcel argued that the key is in understanding that every dollar currently residing in accumulated depreciation will be needed to retire these plants. Consequently, every dollar of accumulated depreciation that is used instead to lower the revenue requirement over the next five years (as proposed by XLI) will need to be paid back over the remaining life. In addition, every dollar currently residing in accumulated depreciation also reduces rate base by a dollar, lowering its revenue requirement.

According to Xcel,[64] the effect on future depreciation expense is more pronounced for nuclear production assets than for TD&G assets. The TD&G asset groups are continually being retired and replaced. Therefore, the need for repayment of any surplus used to reduce near-term revenue requirements can be spread over a large number of years. In contrast, each nuclear unit has an ever shrinking remaining life over which repayment must occur.

[62] Perkett Rebuttal pp. 7-14

[63] Perkett Rebuttal p. 10

[64] Perkett Rebuttal p. 13

Xcel offered an alternative approach to amortizing the surplus. According to the Company an extension of the useful life between five to ten years beyond the operating license period could reduce the current revenue requirement for the Minnesota jurisdiction by approximately $15 to $25 million and would smooth out the costs for what are largely the same customers who make use of the plant near the end of its life. This approach does not overcharge current customers in the event that there would be another license extension for its plants.

Department of Commerce

Campbell Rebuttal pp. 2 -4

The Department stated it does not support XLI's proposal to use a supposed surplus in theoretical depreciation reserves to provide a short-term reduction in rates, for several reasons. First, the "surplus" is only an estimate, not a guaranteed surplus. Second, even if the surplus were known for a fact to exist, the Department does not support a short-term reduction in rates that would result in ratepayers having not only to repay this depreciation expense but also to pay a return on higher rate base as well. In the Department's view this short-term rate reduction would be short sighted and would result in higher rates for ratepayers in the long run.

OAG

Lindell opening statement:

First, the amortization of reserve deficiency. In my direct testimony I discussed how this new concept of amortizing depreciation reserve is a bad policy decision. The question that needs to be answered is how will this affect future rates five to ten years from now. No party addresses that. Instead there is this misconception that somehow doing the reserve depreciation amortization is beneficial for ratepayers by lowering the increase in this case. It is not. Ratepayers will be paying for depreciation twice and also pay a return on the higher rate base that results from the amortization of the depreciation reserve. This actually harms ratepayers. XLI and the DOC, support rate moderation through depreciation reserve amortization that only reduces rates temporarily. These rate moderation proposals do not achieve any real rate reductions for ratepayers. Xcel's witness strongly opposed the depreciation reserve amortization in Xcel's last two rate cases but now supports it.

The Commission has rules requiring annual and five year depreciation certifications that require a thorough analysis of depreciable lives of assets and depreciation expense. That analysis has not been done here in this rate case. That is the proper forum to determine whether the depreciation reserve should be amortized. XLI wants to pile on this concept and do even more depreciation reserve amortization without considering what the impact will be on future rates. XLI should be participating in those depreciation proceedings to address what it considers excess depreciation expense recorded in the past. XLI's proposal, like Xcel's accelerated amortization proposal, is ill conceived and fails to properly analyze the impact its proposal will have on ratepayers in the future.

There is also a procedural concern regarding NSP's proposal to change what the Commission decided a little over one year ago. The Commission's decision in the last case was to amortize the depreciation reserve over eight years. Now parties are proposing to do more depreciation reserve amortization and to amortize the costs on an accelerated basis. The Commission's rules require straight-line depreciation and the accelerated proposal conflicts with the Commission's rules and therefore requires a variance. No one has requested to vary the depreciation rules that require straight-line depreciation.

To summarize, it is simply bad ratemaking to manipulate the depreciation expense to achieve some fairly significant rate reductions in this case. There will be a huge price to pay in the future if these proposals are approved. The OAG does not want to be a party to that type of rate manipulation that will only harm ratepayers in the future.

XLI

Pollock Direct pp. 9-19
Pollock Surrebuttal pp. 8-19

NSP's analysis indicated that as of December 12, 2012, there is a reserve surplus of $97.5 million (Total Company). This translates into $72.5 million for the Minnesota retail jurisdiction.[65] The XLI[66] stated that NSP's analysis is flawed and severely understates the magnitude of the depreciation reserve surplus that it has accumulated in the nuclear production plant accounts. According to the XLI, NSP has accumulated a $236.1 million (Minnesota retail) surplus in its nuclear depreciation reserve. The XLI argued that a large depreciation reserve surplus means that the current generation of customers is subsidizing future customers. In other words, there is intergenerational inequity.

As evidenced in the Final Order in NSP's last rate case, the Commission agreed that a large depreciation surplus results in an intergenerational inequity. In ordering an eight-year amortization of the surplus transmission, distribution and general plant depreciation reserve, the Commission stated:

> Contrary to the arguments of Xcel and the Department, amortizing the surplus over the remaining life of the transmission, distribution, and general plant in a straight-line fashion would spread the benefit of the surplus away from the customers that bore the disproportionate cost—frustrating the very policy that straight-line depreciation is intended to promote.

[65] Pollock Direct p. 10
[66] Pollock Direct p. 11

The XLI[67] stated that the theoretical reserve is almost always different than the book reserve. However, the purpose of depreciation is to recover capital investment, including removal costs. Such recovery should, to the extent possible, come from the customers that use the utility service. Minor differences between the theoretical and book reserve are not unusual and indicate that the Company is generally on schedule to recover the existing investments over the projected remaining life. A large depreciation surplus indicates that the current generation of ratepayers has paid a disproportionate share of the assets consumed to provide utility services. This is neither fair nor equitable, as the Commission found in NSP's last rate case, and should be remedied with short-term amortization of the surplus.

According to XLI,[68] NSP's quantification of surplus depreciation reserve for its nuclear production plant accounts includes two major flaws which understate the level of the reserve surplus. The two flaws are:

- The remaining life values used in the theoretical reserve calculations are understated because NSP included future (i.e., post-test year) interim plant additions. This inflates theoretical reserve amounts causing an understated reserve surplus.

- The theoretical reserve amounts are calculated by account total and not by individual vintages within each account. This method distorts the results because it relies solely on age. The theoretical reserve is a function of age and average service life.

It goes against logic that interim additions that might be made 10 – 15 years in the future would be used to impact the theoretical reserve level at 12/31/2012. Further, NSP's methodology would be contrary to the definition of depreciation which relates to the recovery of current invested capital.

The potential impact of using NSP's method is that at best, the method would understate the surplus depreciation reserve (i.e., the amount by which book reserve exceeds theoretical reserve). The XLI[69] stated it calculated the theoretical reserve correcting the two flaws in NSP's analysis. Its analysis of the nuclear production plant accounts indicates a reserve surplus of $317.6 million ($236.1 million on a Minnesota retail basis). This is $220.2 million higher than the surplus calculated by NSP.

With NSP's customers facing unmitigated base revenue increases for the foreseeable future, the XLI recommended that the Commission require NSP to amortize the nuclear production depreciation reserve surpluses over 5 years. This would reduce test year depreciation expense by $29.6 million (Minnesota retail).[70] The XLI argued that not only would a five-year amortization help to mitigate the rate increase proposed in this case, it would help restore intergenerational equity for current customers.

[67] Pollock Direct p. 12
[68] Pollock Direct p. 13
[69] Pollock Direct pp. 17-18
[70] Pollock Direct Schedule 2

The XLI[71] stated in response to Xcel and the Department, that the commission has already addressed whether surplus depreciation should be used to mitigate future rate increases in its September 3, 2013 Order in Xcel's prior rate case 12-961. In that Order, the Commission directed parties to explore amortization of nuclear depreciation surplus in Xcel's next rate case. According to the XLI, although NSP determined that there was indeed a depreciation surplus, it understated the magnitude of the surplus, and further, it declined to use this surplus to mitigate the 2014-2015 rate increases.

Further, ignoring the surplus would result in current rates exceeding current costs, thereby violating a cardinal ratemaking principle. To accept the recommendations from the Department and Xcel would be inconsistent with the principle of intergenerational equity.

According to the XLI[72], the Department asserted that the nuclear surplus is only an estimate, not a guaranteed surplus, and the existence of a surplus in the nuclear reserve accounts is not reasonable because the claim is focused only on past depreciation and does not consider what is expected to occur during the 2014 and 2015 timeframe and the remaining lives of the nuclear facilities. The XLI stated that the Department's analysis consists of observations about future costs that NSP is seeking to recover in this rate case but doesn't show that a depreciation reserve surplus does not exist.

A depreciation surplus reflects whether recovery of past capital investment is on track given the known "mortality" characteristics of the assets in question. There is guarantee that a depreciation surplus exists because a significant nuclear depreciation surplus has been indicated in several past depreciation studies. It is a logical result of the life extensions that both the Monticello and Prairie Island nuclear plants have undergone.

The XLI stated that a significant increase in nuclear investment would not affect the magnitude of the surplus nuclear depreciation reserve. Further, it is not appropriate to consider plant additions in setting depreciation rates. This would be contrary to the definition of depreciation which relates to the recovery of invested capital. The capital recovery aspect of depreciation is well known and accepted. For example:

> It should be remembered that, under regulation, book depreciation is provided for the purpose of recovering the original investment in the assets concerned, and not for providing for their replacement. Thus, book depreciation is often referred to as capital recovery.

XLI Surrebuttal Schedule 20 shows the annual revenue requirement under (1) the remaining life method, as Xcel and the Department propose, and (2) assuming that a depreciation surplus is amortized over five years as XLI proposes. XLI stated that although there are differences in the annual revenue requirements, there is no difference on an NPV basis between the two

[71] Pollock Surrebuttal pp. 8-9
[72] Pollock Surrebuttal pp. 10-11

depreciation practices. However, by employing accelerated depreciation of the surplus (as XLI proposes), intergenerational equity will be restored.

The Department asserted that amortizing a depreciation surplus creates a short term rate reduction and future payback requirement. The XLI stated that this is not a legitimate reason to ignore the surplus. The Department's conclusions about the non-existence of a reserve surplus and adverse future rate impacts of accelerating the depreciation of a surplus depreciation reserve are unfounded. The magnitude of the surplus is unaffected by subsequent plant additions.[73]

XLI stated that Xcel has provided no justification for rejecting vintage accounting in determining the theoretical depreciation reserve. Further, its opposition to using the surplus nuclear depreciation to mitigate the 2014-2015 rate increases is founded on a false premise that the surplus is needed to absorb future capital additions in light of the finite remaining lives of NSP's nuclear plants. For all of the reasons cited, the Commission should use the $318 million surplus to mitigate the 2014-2015 rate increases. This would provide an additional $30 million per year of rate moderation over the next five years.

ALJ Report

Findings 587-619

614. In this case, both the Company and XLI have demonstrated, based on financial analysis, that a nuclear depreciation reserve surplus exists. They disagree, however, as to the amount of the reserve.

615. With regard to the calculation of the amount of the surplus, the Administrative Law Judge agrees with the Company that the vintage accounting method is not appropriate for determining the nuclear plant depreciation expense because the useful life of a nuclear power plant is determined by its license. Contrary to XLI's assertion, it is not reasonable to assume that the licenses for the Prairie Island and Monticello plants will be extended beyond their existing terms. There are no pending extension requests for either Prairie Island or Monticello and, even if there were, NRC approval is not guaranteed.

616. The Administrative Law Judge, however, questions the Company's inclusion of future plant additions in its calculation of the nuclear depreciation reserve surplus. As noted by XLI, depreciation is intended to recover the costs of capital that is already invested, not future investments. Nonetheless, inclusion of the future interim additions is helpful for understanding the likely impacts on ratepayers.

617. Based on this analysis, the Administrative Law Judge concludes that XLI's calculation of the nuclear depreciation surplus likely overestimates the surplus because it is based on vintage

[73] Pollock Surrebuttal pp. 13-14

accounting. Conversely, the Company has likely underestimated the surplus by including interim plant additions.

618. Because XLI has likely overestimated the nuclear reserve surplus, the Administrative Law Judge recommends the Commission reject XLI's proposal to amortize $208 million in nuclear production depreciation reserve over five years. Whether the Commission should order amortization of a smaller amount (such as the $72.5 million surplus calculated by the Company) or take no action will depend on the determination of the size of the revenue deficiencies in 2014 and the 2015 Step and will require consideration of a variety of factors such as rate shock mitigation, rate stability, intergenerational equity, and the need to ensure adequate funding for plant retirements. The Commission may also want to consider the potential rate impacts of adopting one or both of the Company's proposed rate moderation proposals, which are discussed below, in making its determination regarding treatment of the nuclear plant depreciation reserve surplus.

Staff Analysis

According to Xcel, the primary driver of the reserve surplus for Prairie Island is the fact that between 1994 and 2003, the remaining life for the plant was kept 6.5 years shorter than its approved NRC license life. Due to a change in state law, during that period there was significant uncertainty regarding the Company's ability to store enough dry spent nuclear fuel on-site to support operations until the end of its approved license life. As this situation could have caused early retirement of the Prairie Island plant, the Company requested, and the Commission approved, that costs be recovered over a shorter period to minimize potential financial risk to the Company.

Based on Xcel's statement it appears that it charged excess depreciation during that period which resulted in an intergeneration inequity. Further, in a presentation at the 2014 EEI Financial conference held November 11-13, 2014, an Xcel officer's power point presentation[74] showed under potential actions to improve earned ROE, the use of nuclear depreciation surplus as a mitigation tool.

Further, the XLI analyzed the NPV of the depreciation expense stream of its recommendation and that of the Xcel/Department recommendation and found that the NPV of the both was essentially the same. Therefore, there should not be a concern with making a refund now and paying higher depreciation expense later.

If the Commission wants to use the difference between the nuclear theoretical and actual depreciation reserve to mitigate rates there is support for doing so. The question is what reserve amount should be used. The ALJ concluded that Xcel's number is too low because it included future costs and XLI's is too high because it used a vintage calculation.

[74] http://investors.xcelenergy.com/presentations.aspx?iid=4025308 page 7

Xcel reserve surplus is $72.5 million for the Minnesota jurisdiction. According to Xcel,[75] the XLI increased the theoretical reserve by $41.5 million (Minnesota Jurisdiction) by ignoring the need for future capital additions. Because Xcel's reserve surplus was understated because it included future capital additions, adding the two together ($114 million) should provide a reasonable number to be amortized if the Commission wishes to pursue this for rate mitigation.

Xcel proposed an alternative to extend the useful life of the nuclear plant between five to ten years beyond the operating license period. Staff questions the viability of this option. It is unknown if the operating life of the plant could be extended in the future. The Company just spent a considerable amount of money for the current life extension. Part of that cost was due to deterioration of the plants in the second 20 years of their life. It is likely that if the license were to be extended for an additional 20 years, that would require significant capital expenditures at that time. It may not be justified to make those expenditures to keep the plant operating for the additional 20 years. If the plant license were not extended, ratepayers would then be paying for a plant that is not producing electricity.

Decision Alternatives

Nuclear Theoretical Depreciation Reserve

1. Do not amortize the difference between the actual and theoretical depreciation reserves for the nuclear plant and allow the difference to self-correct over the life of the plant. (Xcel, DOC, OAG)

2. Determine that difference between the actual and theoretical depreciation reserves of $236.1 million for the nuclear plant should be returned to rate payers by amortizing that difference over five years. (XLI)

3. Determine that difference between the actual and theoretical depreciation reserves of $114 million for the nuclear plant should be returned to rate payers by amortizing that difference over five years or some other period as determine by the Commission.

4. Allow Xcel to extend the useful life of the nuclear plants between five to ten years beyond the operating license period. (Xcel alternative)

(Note: The decision alternatives for this item correspond to alternative VII, G (1 through 4) on p. 43 of the deliberation outline.)

[75] Perkett Rebuttal p. 7

MYRP in General

PUC Staff: Jerry Dasinger

Xcel

Sparby Direct pp. 16-18
Sparby Rebuttal pp. 10-12
Clark Direct pp. 6-10
Clark Rebuttal pp. 2, 4-8
Heuer Direct pp. 6-7

Xcel[76] stated it is proposing a rate increase for the 2014 test year with a 2015 step increase. The 2015 step increase includes costs associated with certain capital additions in 2015 and three specific non-capital costs in 2015 that are related to capital investments. From a Company investment perspective, it is placing significant capital investments in-service in both 2014 and 2015. Proposing the multi-year rate plan enables it to request recovery of a full year of costs associated with 2014 projects and to request recovery of certain 2015 projects that are too large for it to forego initial recovery until 2016.

The Company[77] stated that a multi-year rate plan provides the following benefits for customers, regulators, and shareholders, as well as the utility:

- Provides rate predictability and potential moderation of the pace of rate increases.
- Provides potential regulatory efficiency improvement.
- Provides a longer-term view of costs and investments for customers and regulators.
- Facilitates investments that support state energy policy goals.
- Reduces regulatory lag beyond the single test year.

Even though a multi-year plan may not allow recovery of the full cost of service in a given year, the company supports moving to a multi-year rate plan because it believes the multi-year rate plan is part of a transition in the regulatory model.

Currently, the Company is in the peak years of its investment cycle. The multi-year rate plan allows the Company a mechanism to help recover these investments and provides a platform for it to moderate the impact of the recovery on customer rates. Given the magnitude of its investments over the last several years, a multiyear rate plan is also needed to fully annualize the costs of 2014 capital investments to support adequate cost recovery. Taken together, these considerations warranted a two-year rate proposal for 2014 and 2015.

[76] Sparby Direct pp. 16-18
[77] Clark Direct pp. 6-10

Xcel stated that consistent with the Commission's Order Points 1 and 15, its 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.

According to Xcel,[78] it continues to expect that a multi-year rate plan will provide benefits to stakeholders through both years of the plan and into 2016. It believes the multi-year rate plan will provide these benefits so long as it is implemented in a manner that balances the interests of all Company stakeholders. By utilizing the multi-year framework, it can provide its customers with greater year-over-year rate predictability, rate moderation, and regulatory efficiency. At the same time, the Parties can continue to consider 2014 and 2015 in relation to each other, identify ways to minimize or avoid the relative increase for customers in 2016, and seek the most effective final outcome for its customers and other stakeholders.

However, it is important to recognize that, by definition, a multi-year rate plan precludes a utility from returning for a new rate increase during the term of the rate plan, despite a rising cost environment. In the case of a limited multiyear rate plan such as this, where the revenue deficiency for the second year of the plan utilizes many unchanged revenue and cost elements from the test year, it becomes particularly important to establish reasonable levels of revenue and costs for the test year to ensure the overall feasibility of the multiyear rate plan construct.

The Company stated its proposed multi-year rate plan does not capture the Company's full revenue deficiency for each year of the plan. Its 2014 test year follows the typical construct in which all revenues, expenses, and capital costs are incorporated into the test year. For 2015, it proposed a limited Step that captures only $98.5 million of its full expected 2015 revenue deficiency of $134.98 million. In a more traditional multi-year rate plan, the Company would request full recovery of its total revenue deficiency in each year of the plan.

In Rebuttal, the Company[79] stated it continues to support the use of a multi-year rate plan, rate moderation, and a revenue decoupling mechanism to help address challenges and balance interests in this case. These proposals represent an incremental step toward a more sustainable regulatory model that supports needed long term investments, incentivizes efficient operations, and facilitates enhanced customer options and achievement of policy goals.

Xcel[80] stated that both the Minnesota Legislature and the Commission have approved the multi-year rate plan construct. While it could in theory withdraw the Step proposal and file a separate rate case for 2015 (consistent with the suggestion of Institutional Customer Intervention Group (ICI) witness Mr. William Glahn), the Company does not believe this option would be cost effective or beneficial for its customers or other stakeholders.

The Company believes the better course is to achieve the intent of the legislation by establishing an appropriate multi-year rate plan that provides for sufficient recovery in both years to allow the Company to operate effectively and provide reliable service during this period.

[78] Clark Rebuttal pp. 5-6
[79] Sparby Rebuttal p. 10
[80] Clark Rebuttal pp. 7-8

ICI

Glahn Direct pp. 6-9
Glahn Surrebuttal pp. 1-2

The ICI stated that as described by Xcel witness Sparby, the utility has proposed to phase-in their proposed rate increase over a two-year period. Implicit in Xcel's proposal is the idea that absent the phase-in, their full rate request would not be moderate and needs to be made more gradual.

Also implicit in the phase-in proposal is the idea that the utility cannot justify the full rate increase at this time and hopes that by deferring most cost recovery into the future, less scrutiny will fall upon their immediate request for additional cost recovery.

The ICI stated it thought the timing of the proposal was curious. In a recent edition of The Value Line Investment Survey covering the electric utility industry (Central region), the publication included this analysis:

> In the past, electric utilities could count on load (demand) growth to offset at least some of the effects of regulatory lag. However, for most utilities load growth has slowed in recent years due to the severe recession from late 2007 to 2009, the sluggish economic recovery once the recession ended, and the effects of energy-efficiency programs.

The implications of this analysis should be clear. Xcel's rate increase request comes at a time of a sluggish economic growth in Minnesota and elsewhere. As the broader economy picks up momentum, Xcel should enjoy new opportunities for additional sales to native customers and more opportunities for off-system sales in the wholesale market. Xcel's financial picture could look considerably brighter in the next 12 to 24 months, while the additional rate increase will already have been locked-in.

What Xcel proposed with its two-year phase-in is moving from regulatory "lag" to a form of regulatory "lead," where rate increases are determined based on forecasts of future investments, not on actual results.

The ICI argued that an improving economy will put Xcel in a position to over earn based on rates that in retrospect turned out to be too high. Given the prohibition against on retroactive ratemaking, Xcel would then be in a position to keep all, or at least a substantial portion, of the resulting windfall.

According to the ICI, Xcel proposes to implement the phased-in two-year increase as follows:

> We anticipate submitting an updated filing in October 2014, providing actual results for 2013, and any changes to the 2014 forecast impacting then existing interim rates. The Company will work with parties and stakeholders on this issue to ensure that any proposed interim rate changes are reasonable…

The ICI argued that what Xcel proposes is something akin to a rolling rate case, where the company updates some figures, submits new assets for inclusion in rate base, but provides far less than a comprehensive review of the utility's financial condition. Instead, only selected asset additions (and related costs) will be considered. The inclusion of only items selected by the utility in calculating 2015 rates—classic piecemeal ratemaking—tilts the playing field against the interests of customers who will not have access to the entirety of Xcel's financial data.

As it happens, Xcel plans to institute a hideously complicated process for setting next year's rates—involving an internal " Step review committee," a complex refund mechanism, additional compliance and annual reporting requirements and customer notices --all to accelerate cost recovery by a handful of months for a selected few items.

The ICI recommended that the Board institute a one-time rate change that does not produce rate shock and that can be fully-justified at this time. Rates set in this proceeding should reflect assets in place as of 2014. Should circumstances move in a less favorable direction for Xcel in the next year or two, or should investments made in 2015 or 2016 require immediate attention they have the opportunity to return to the Board seeking another rate increase.

The ICI argued that even with the risk of annual, consecutive rate cases, consumers benefit from the transparency of having all revenue and expenses examined at one time in one proceeding.

[81]The ICI suggested that the number of issues raised in regards to the utility's multi-year proposal argues against the plan's merits. It turns out that a multi-year plan does not simplify the ratemaking process, it complicates it. Rather than having to make the number of adjustments and account for the number of contingencies built into the plan, the ICI continues to support its original recommendation to approve a single-year rate increase.

ALJ Report

Findings 636-642

642. The concerns of the ICI Group regarding the Company's proposed MYRP go to the underlying policy question of whether a MYRP is a sound regulatory tool. In 2011, the Minnesota Legislature determined that MYRPs can be beneficial when it enacted the law allowing utilities to propose MYRPs to the Commission. Pursuant to Minn. Stat. § 2168.16, subd. 19, the utility has the burden of proving the proposed MYRP will result in just and reasonable rates for its customers. As discussed in the other sections of this Report, the record in this case shows the Company's proposed MYRP, as modified in this Report, will result in just and reasonable rates. Therefore, the Administrative Law Judge recommends that the Commission deny the ICI Group's request to limit any rate increase to the 2014 test year.

[81] Glahn Surrebuttal pp. 1-2

Staff Analysis

The legislature granted statutory authority for multiyear rate plans. The Commission has established guidelines for multiyear rate plans. In this case, the filing was accepted and set for hearing knowing it was a multiyear rate plan. Staff is unaware that any party other than the ICI that argued that the MYRP would not result in just and reasonable rates. The ICI did not present any evidence to support the idea that the MYRP will not result in just and reasonable rates. Without that evidence, there is nothing in the record to support rejecting the MYRP proposal.

Decision Alternatives

MYRP in General

1. Deny the ICI Group's request to limit any rate increase to the 2014 test year. (ALJ, Xcel)

2. Approve the ICI Group's request to limit any rate increase to the 2014 test year. (ICI)

(Note: The decision alternatives for this item correspond to alternative VII, H (1 and 2) on p. 43 of the deliberation outline.)

Rate Moderation Proposal – TDG Theoretical Depreciation Reserve Surplus

PUC Staff: Jorge Alonso

Introduction

This issue is disputed between Xcel, the Department and the OAG. To help mitigate the rate increase amount, the Company proposed to accelerate the amortization of the theoretical book reserve (“Theoretical Depreciation Reserve”) for the transmission, distribution, and general (TDG) assets. The Company proposed to accelerate return of the remaining theoretical depreciation reserve surplus to customers by amortizing it over the next three years: 50% in 2014, 30% in 2015, and 20% in 2016. The Department recommended a different amortization schedule - 50% in 2014, 40% in 2015, and 10% in 2016; however, it stated that it would not object to the Company’s proposal. The OAG opposed usage of the Theoretical Depreciation Reserve.

Note: Parties positions that repeat or reaffirm a previous position are not repeated; however, all references on the record of this subject are listed at the bottom of this section.

Party Positions

Xcel – Direct Testimony

To reduce the revenue deficiency that the Xcel would otherwise recover through rates, the Company proposed to return the depreciation surplus over the next three years by amortizing 50% in 2014, 30% in 2015, and 20% in 2016. The Company selected the different percentages with the goal of establishing approximately a 5% year-over- year increase in rates over the next two years.

The Company provided the following table showing the revenue requirement impact, when compared to the eight year amortization schedule currently in place, of the proposed amortization is a reduction in revenue requirements of $81 million in 2014 and $30 million in 2015:

Revenue Requirement Impacts of Proposed Amortization of Excess Theoretical Reserve Balance

Year	Proposed Amortization Percentage	Rev. Req. for Proposed Amortization Percentage	Rev. Req. for Current 8-Year Amortization	Impact Difference: Proposed – 8 Yr.
2014	50%	($111,308,000)	($30,248,000)	($81,061,000)
2015	30%	($58,387,000)	($28,117,000)	($30,270,000)
	2015 Step Amount	*$52,921,000*		

Department of Commerce – Direct Testimony

The Department expressed concerns regarding Xcel's rate mitigation proposals, including the use of DOE excess settlement amounts (this topic is discussed separately). The Department cautioned that, while rate ratepayers did see benefits of a $32.655 million reduction in 2013 and will likely see benefits of a $78.913 million reduction in 2014, ratepayers, depending on the mitigation alternative selected, will also get increases of $7 to $30 million in 2015 and $63 to $121 million in 2016.

Based on its review, the Department recommended a 50-40-10% split which, in combination with the DOE funds, results in the following comparison:

	2014	2015	2016
50/30/20% w DOE	$78.913	$17.084	$63.157
50/40/10% w DOE	$78.913	$5.188	$74.315

As an alternative, the Department indicated that it support Xcel's proposed split.

Office of Attorney General – Direct Testimony

The OAG characterized NSP's moderation adjustment as an attempt to make its rate increase request seem more reasonable. The OAG noted that Xcel has not offered any real moderation; it has simply proposed to shift costs forward to be paid by future ratepayers.

Xcel – Rebuttal Testimony

Xcel disagreed with the OAG's position and reiterated its position that rate moderation proposal serves to balance its rate increases over time as compared to a traditional straight-line amortization of its theoretical reserves and, as such, it is appropriate to adopt this accelerated approach for the customers' benefit.

Xcel also examined other moderation alternatives, such as a 50-0-50 split; however, it continued to recommend its initial proposal because it helps the trend of rate predictability by avoiding larger year-over-year increases.

ALJ Report

In Findings 620 through 632, the ALJ Report discussed all the various rate mitigation alternatives on the record. Finding #632 detailed the ALJ's recommendation:

> 632. With regard to the Company's proposal to accelerate return of the TDG reserve surplus, the Administrative Law Judge agrees with both the OAG and the Department that accelerating the return will reduce rates in the short-term but result in higher rates in later years. Notwithstanding this fact, there may be circumstances where such an approach would be warranted to avoid rate shock in the short-term and/or to address intergenerational equity. Moreover, in this case, the Commission authorized the use of a 50/30/20 percent approach in setting the interim rates. As a result, it may be reasonable to continue some form of accelerated return of the TDG depreciation reserve surplus in final rates.

Decision Alternatives

<u>Decision alternatives for TDG Theoretical Depreciation Reserve Surplus</u>

1. Approve accelerated usage of the Theoretical Depreciation Reserve split as a rate moderation tool in this case and determine that the 50/30/20 split should be used. (Xcel, DOC alternate, ALJ)

2. Approve accelerated usage of the Theoretical Depreciation Reserve split as a rate moderation tool in this case and determine that the 50/40/10 split should be used. (DOC)

3. Deny accelerated usage of the Theoretical Depreciation Reserve as a rate moderation tool in this case. (OAG)

(Note: The decision alternatives for this item correspond to alternative VII, I (1 through 3) on p. 44 of the deliberation outline.)

Reference to Record
Xcel Direct: Clark, page 27 starting at line 1
Xcel Direct: Heuer, page 92 starting at line 17
Xcel Direct: Perkett, page 36 starting at line 5
Xcel Direct: Robinson, page 31 starting at line 13
DOC Direct: Campbell, page 93 starting at line 14
OAG Direct: Lindell, page 15 starting at line 6
Xcel Rebuttal: Clark, page 39 starting at line 9
Xcel Rebuttal: Robinson, page 16 starting at line 4
Xcel Rebuttal: Sparby, page 12 starting at line 21
DOC Surrebuttal: Campbell, page 68 starting at line 1
Xcel Initial Brief: Starting on page 97
DOC Initial Brief: Starting on page 239
Xcel Reply Brief and Proposed Findings: Starting on pages 80 and 93, respectively
DOC Reply Brief: Starting on page 175
ALJ Report: Findings 620-632, starting on page 143

Depreciation and Plant Retirements in the 2015 Step – Passage of Time (2015 Step)

PUC Staff: Jorge Alonso

Introduction

This issue is disputed between Xcel and the Department. The Department argued that Reductions in depreciation expense for the passage of time in the 2015 MYRP are needed. The Company disagreed.

Note: Parties positions that repeat or reaffirm a previous position are not repeated; however, all references on the record for this subject are listed at the bottom of this section.

Party Positions

Department of Commerce – Direct Testimony

The Department noted that the Commission's Multiyear Rate Plan Orders provide for rate recovery of costs related to specific, clearly identified capital projects, and appropriate non-capital costs. Additionally, Ordering Point 15 A (under Application Requirements) provides for specific capital projects for which the utility seeks to recover capital costs – and, where appropriate, non-capital costs – via the plan. The Department considered this language to support an adjustment to recognize the reduction in nuclear amortization expense from 2014 to 2015.

The Department mentioned that, consistent with the Company's updating its property tax amount for related new capital investment, it is appropriate to reflect depreciation expense and related accumulated depreciation for the passage of time from 2014 to 2015 and capturing 2015 plant retirements, for purposes of the 2015 step. These adjustments are known and measurable numbers based on simply reflecting the depreciation expense and accumulated depreciation from 2014 to 2015 and, for existing plant currently in rate base and being paid for by ratepayers, capturing plant retirements.[82]

The Department pointed out that, for the 2015 Step Year, Xcel requested recovery for 36 capital projects. Those projects translate to a $68.865 million revenue requirement increase. The Department considered it inequitable to allow the Company to include these plant additions without reflecting reduced depreciation expense and related accumulated depreciation for existing plant in rate base for the passage of time from 2014 and 2015 and capturing 2015 plant retirements.[83]

The Department explained that, although there is not an impact for 2015 retirements for remaining life generation plant, there is an impact for transmission and distribution plant for 2015 which is depreciated using an average service life method. Specifically, for 2015 transmission and distribution retirements, depreciation expense is reduced; however, there is a slight increase in rate base due to the decrease in accumulated depreciation, and related current and deferred taxes.[84]

Based on data obtained through IRs and its analysis, to reflect 2015 retirements for transmission and distribution facilities, the Department recommended that the Commission approve a downward adjustment of $535,552 to the Company's 2015 revenue requirement. Similarly, the Department recommended a $17,529,000 reduction to 2015 revenue requirements for 2015 depreciation expense and accumulated depreciation due to the passage of time for all plant in rate base, except 2015 step projects already incorporated in the 2015 step revenue requirement.[85]

[82] Campbell Direct, page 158
[83] Ibid
[84] Ibid, page 159
[85] Ibid, page 160

The Department summarized its arguments for the two adjustment recommendations as follows[86]:

1. practically, the Company's 2015 rate base is lower for existing plant in rate base (not including 2015 capital step projects) as result of 2015 retirements and 2015 depreciation expense and accumulated depreciation recorded due to the passage of time, so ratepayers should not pay a return on a higher 2014 rate base which the Company is not actual incurring, for purposes of the 2015 step;

2. equitably, it is unfair not to update for the 2015 retirements and 2015 depreciation expense and accumulated depreciation for the passage of time for existing plant in rate base for which ratepayers are currently paying, while at the same time requiring ratepayers to pay for higher depreciation amounts and higher rate base amounts caused by the 36 capital projects in the Company's 2015 step; and

3. updating for 2015 plant retirements and 2015 depreciation and accumulated depreciation is consistent with the Department's comments and Commission's Order in the MYRP where updates for capital and capital related items such as depreciation and taxes are appropriate.

Xcel – Rebuttal Testimony

Xcel characterized the Department's proposed adjustment asymmetrical. The Company stated that the Department included the increase in the accumulated depreciation reserve from non-Step projects placed in service in 2014, which has the impact of reducing rate base, did not include the actual increase in plant from this same group of projects, which increases rate base and did not include the annualization of depreciation expense for these projects. Xcel asserted that 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. The Company pointed out that, if its approach is taken, the result is not a $17.5 million reduction, but a $1.9 million increase. Xcel opined that broad and complete application of the Department's proposed adjustment would move toward a full capital requirements rate case, which is a different approach to the Commission's Multi-Year Rate Plan Order.[87]

Xcel argued that the recommendations rely upon the Commission's Multi-Year Rate Plan Order to support adjustments for capital related costs that reduce the Company's 2015 revenue deficiency without recognizing that it did not include a substantial number of its capital projects for 2015. The Company added that it did not include most O&M items that are likely to increase, including insurance, labor, and distribution maintenance. Xcel postured that, if the Department prefers to address cost decreases not tied to specific capital projects included in the

[86] Ibid, page 164
[87] Perkett Rebuttal, page 5

Step, it believes that it would be most appropriate to move forward with a fully-developed multi-year rate plan in which the Company's total revenue deficiency is potentially recoverable.[88]

The Company pointed out that the 2015 rate base increase is $713.4 million (Total Company) and the proposed 2015 Step rate base for the 36 projects is $579.9 million (Total Company); therefore, the difference is $133.5 million. Xcel claimed that the $133.5 million is *inclusive* of the reduction to rate base that occurs due to the passage of time adjustment. Since overall rate base is increasing more than the 2015 Step proposal, the Company concluded that there is no need to apply a passage of time adjustment. Xcel also added that Total Company rate base additions not included in the 2015 Step (prior to the passage of time adjustment) are $350 million, which more than offsets the $216 million Total Company passage of time rate base adjustment.[89]

Regarding the Department's proposed adjustment for 2015 retirements, Xcel stated that it does not consider the scope of the second year of a multi-year plan to be similar to a full test year where all year over year changes in the historical asset base year over year are factored; therefore, if this proposed adjustment for retirements of plant not included in the 2015 Step is included, then the annualized plant depreciation expense for all of the 2014 additions should be included as well.[90]

In closing, Xcel stated that a passage of time adjustment, if appropriate, would need to capture all 2015 impacts of 2014 additions, not just the change to accumulated depreciation reserve, which is the one element that everyone would expect to reduce revenue requirements. When all elements are considered, the passage of time adjustment would support an increase rather than a decrease to the 2015 Step. For these reasons, no adjustment is appropriate.[91]

Department of Commerce – Surrebuttal Testimony

The Department noted that the Company recorded all revenue requirements components (including depreciation) for the 36 capital projects included in their 2015 Step. It also added that Xcel selected the 36 capital projects, which either went into service for part of 2014 or were projects that went in-service in 2015, so for all of these 2014 projects, depreciation was annualized. The Department pointed out that, since every single capital project increased the Company's revenue requirement, inclusion of all 36 capital projects clearly benefited the Company. Therefore, the Company's 2015 Step method does a good job of capturing all increases in capital investment, but does not capture the reduction in 2014 capital projects (rate base) due to the normal passage of time, for projects that the Company did not include in its 2015 Step. The Department considered the Company's proposal one-sided and unreasonable.

[88] Clark Rebuttal, page 34
[89] Perkett Rebuttal, page 4
[90] Ibid, page 6
[91] Ibid, page 7

The Department also pointed out that Xcel's proposal to increase partial year depreciation for projects placed in service in 2014 to reflect an entire year of depreciation in 2015 completely contradicts Xcel's proposal not to decrease rate base (by increasing accumulated depreciation reserve) in 2015 for all capital projects to reflect the passage of time. Moreover, in a traditional rate case depreciation and rate base are not annualized for capital projects that are placed in service in the test year, so the Company's argument that they are entitled to annualized depreciation for all 2014 projects in the 2015 Step is incorrect.[92]

The Department noted that the adjustment is necessary because it is known that customers would pay too much for these costs if they continued to pay 2014 rates in 2015 in the context of a multi-year rate case. While the DOC agreed that the Company may recover costs of new capital added in 2015, it also pointed out that it is also known that the rate base also steps down in 2015 due to the passage of time and retirements. As a result, the difference needs to be captured. Regarding Xcel's argument regarding asymmetrical treatment of expenses, the Department stated that that the Company noted that it did not include in the 2015 Step costs for various expenses that, according to the Company, are likely to increase. However, the Department noted that there are also expenses that may go down in 2015 and many revenues that could go up in 2015. Thus, without having evaluated all the 2015 costs and revenues, it would not be reasonable to conclude in this proceeding that ratepayers would be better off with a full review of the full revenue requirements for 2015, which the Company did not propose. Thus, the Department concluded that the Company's argument is not valid.[93]

Xcel – Initial Brief

In addition to reasserting its position, Xcel warning that, should the Commission and ALJ adopt the passage of time adjustment in the instant context, it will send a signal which the Company believes will not advance the use of the multi-year rate plan. 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. For this reason, it believes a passage of time adjustment should not be made.

Department of Commerce – Initial Brief

The Department noted Xcel's arguments that, if it had requested a full 2015 forecast of its revenue requirement, it would have requested $713.4 million rather than the $579.9 million Step and, since the full overall 2015 Step is increasing more than the 2015 proposal, it would be inappropriate to reduce the revenue requirement. The Department stated that Xcel did not prove the reasonableness of these arguments. The DOC also added that Xcel did not seek a rate

[92] Campbell Surrebuttal, pages 111-113
[93] Ibid, page 114

increase in 2015 of $713.4 million and that amount has not been examined or audited for accuracy or reasonableness.[94]

Xcel – Reply Brief

Xcel claims that the Department's methodology has evolved through the proceeding and stated that this new methodology is contrary to the underlying theory behind the passage of time adjustment, which is that, due to the passage of time, the Company's 2015 revenue requirements should be reduced by updating the entirety of the Company's 2014 rate base in 2015 to reflect accumulated depreciation and depreciation expense for the out-years of the Company's MYRP. The Company described the Department's position as a sharp deviation from the theory it espoused in pre-filed testimony and testimony at the evidentiary hearing and egregiously asymmetrical.[95]

Department of Commerce – Reply Brief

The Department addressed Xcel's Initial Brief warning regarding the message a passage of time adjustment would send by pointing out that Minnesota law simply does not include as a ratemaking criterion that the Commission should ignore record evidence, ignore known and measureable changes (the effects of the passage of time and plant retirements on depreciation), or ignore whether or not the utility met its burden of proof. Thus, Minnesota Statutes cannot be read to allow a utility to unreasonably profit from retaining the known and measureable decreases in depreciation and related costs due to the passage of time and to retirements of assets. Since it is known that the utility's level of depreciation costs will decrease due to the passage of time and due to retirements, this decrease in costs must be included as an offset to the increase in such costs due to capital additions in step years of a MYRP. Xcel's proposal would result in unreasonable rates, in violation of Minnesota Statutes section 216B.03, and must be rejected. [96]

The Department also added that the Commission's Order authorizing MYRP required utilities to provide information intended to ensure that the correct level of depreciation in the step year(s) of a MYRP would be set at appropriate levels. Specifically, ordering paragraph 18 states:

> An application for a multiyear rate plan must include or be accompanied by testimony supporting the following aspects of the case:
>
> A. The capital additions that the utility proposes for each year of the multiyear rate plan.
> B. Depreciation lives related to capital additions in each year of the plan.

[94] Department of Commerce, Initial Brief, pages 231-232
[95] Xcel Energy, Reply Brief, pages 36-38
[96] Department of Commerce, Reply Brief, pages 36-37

C. Changes expected in the lives of all depreciable assets for two years after the plan.[97]

ALJ Report

The ALJ discussed the passage of time adjustment in Findings 200 through 234. Her analysis is found on Findings 225 through 233 and her recommendation is given in Finding 234:[98]

225. The question of how changes in rate base, depreciation expense, and accumulated depreciation reserve due to the passage of time should be treated in a MYRP presents an issue of first impression.

226. As noted above, Minnesota law provides that the Commission may approve a MYRP only if it finds that the plan establishes just and reasonable rates, applying traditional ratemaking factors. Those factors include:

> 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, and to earn a fair and reasonable return upon the investment in such property*. In determining *the rate base upon which the utility is to be allowed to earn a fair rate of return*, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature.

227. The language in the italicized provisions above requires the Commission to consider both depreciation expense and changes in rate base in determining whether the MYRP will result in just and reasonable rates. Nothing in the plain language of the statute limits the determination in the step year(s) only to costs associated with specific capital projects.

228. In addition, while the Commission's MYRP ORDER authorizes a utility to "propose" a MYRP to seek recovery of "specific, clearly identified capital projects" and "associated non-capital costs," it also requires that the utility demonstrate that the MYRP will result in just and reasonable rates, applying traditional ratemaking factors.

229. Because those factors include consideration of the utility's depreciation expense and rate base, the Administrative Law Judge agrees with the Department that the Commission should consider the effects of the passage of time on depreciation and rate

[97] Ibid, page 38
[98] ALJ Report, pages 49-51

base in determining the 2015 Step revenue requirement. Otherwise, the 2015 Step will not take into account known and measurable changes in depreciation expense, rate base, and accumulated depreciation reserve for non-Step projects placed into service in 2014, but will only reflect changes due to Step projects. Consideration of the effects due to the passage of time on rate base and depreciation is necessary to ensure just and reasonable rates.

230. A careful review of the record in this case shows that the Department's proposed passage of time adjustments 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 the change in accumulated depreciation for non-Step projects placed into service in 2014; it does not reflect the increased expenses due to annualization of depreciation expense or the 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.

231. 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 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.

232. In an attachment to her testimony, Company witness Ms. Lisa H. Perkett provided a calculation of the increased depreciation expense for the passage of time from 2014 to 2015 excluding 2015 Step projects. This calculation was done to correct an error in the Company's response to Department Information Request No. 2113. This Information Request asked specifically for a calculation of the effect of the passage of time without the 2015 Step projects. As a result, Ms. Perkett's updated calculation also excludes the 2015 Step projects and represents the incremental increase, not the full increase.

233. This conclusion is confirmed by the Rebuttal Testimony of Ms. Perkett. In her Rebuttal Testimony, she calculates the passage of time impact for "non-Step projects placed in service in 2014." "[T]he result is not a $17.5 million reduction [as claimed by the Department], but a $1.9 million increase."

234. 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.

Decision Alternatives

Decision alternatives for Depreciation and Plant Retirements in the 2015 Step – Passage of Time (2015 Step)

1. Find that no 2015 Step Year adjustments for Depreciation, Plant Retirements, and Passage of Time are required. (Xcel, ALJ)

2. To reflect 2015 capital retirements of transmission and distribution facilities, find that a 2015 Step Year reduction adjustment of $535,552 is required. (DOC)

3. To reflect 2015 changes in depreciation due to the passage of time, find that a 2015 Step Year reduction adjustment of $17.53 million is required. (DOC)

(Note: The decision alternatives for this item correspond to alternative VII, J (1 through 3) on p. 44 of the deliberation outline.)

Reference to Record
DOC Direct: Campbell, page 156 starting at line 20
Xcel Rebuttal: Clark, page 33 starting at line 10
Xcel Rebuttal: Perkett, page 3 starting at line 17
Xcel Rebuttal: Sparby, page 12 starting at line 1
DOC Surrebuttal: Campbell, page 109 starting at line 11
Xcel Initial Brief: Starting on page 44
DOC Initial Brief: Starting on page 226
Xcel Reply Brief and Proposed Findings: Starting on pages 35 and 47, respectively
DOC Reply Brief: Starting on page 32
DOC Proposed Findings: Starting on page 166
ALJ Report: Findings 200-234, starting on page 44

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

PUC Staff: Jorge Alonso

Introduction

This issue is disputed between Xcel and the Department. During discovery, the Department identified seven projects included in the 2014 test year that would not be in-service until 2015 and recommended their inclusion in rate base be deferred until 2015. Similarly, the DOC also identified two projects included in the 2015 step-year that would not be in-service until after 2015.

Note: Parties positions that repeat or reaffirm a previous position are not repeated; however, all references on the record for this subject are listed at the bottom of this section.

Party Positions

Department of Commerce – Direct Testimony

The Department revealed that, during discovery, the Company reported that projects totaling $67.3 million, resulting in a $2.18 million revenue requirement, had moved out of the 2014 test year. Xcel also reported that two projects totaling $3.8 million, resulting in a $2.05 million revenue requirement, had moved out of the 2015 step year.[99] Projects moving outside 2014/2015 were summarized in the following table[100]:

Item	Budgeted in 2014	Moved Outside 2014	Percent of Total	Budgeted in 2015	Moved Outside 2015 Step	Percent of Total
Number of projects	733	49	7.4%	116	2	1.7%
Capital Additions (000s)	$954.6	$67.3	7.1%	$932.9	$3.8	0.4%

The Department revealed that, because Xcel had replaced some of these projects like-kind capital projects, the Company did not think that an adjustment was either necessary or appropriate. The Department disagreed and argued that, since the Department would not have adequate time to review all the new capital projects proposed by the Company, allowing them to be included in the rate case would unfairly burden parties in this rate, including the Department, and would not be in the public interest. The Department recommended that the Commission approve a $2.18 million revenue requirement reduction for the 2014 test year and a $2.05 million revenue requirement reduction for the 2015 step.[101]

Xcel – Rebuttal Testimony

Xcel explained that it develops its capital budgets on a five-year rolling basis and, while the Company makes every effort to implement its capital budget as approved, the nature of its business is unpredictable due to condition of equipment, severe weather events, changes to business or customer priorities, or emerging regulatory requirements. These types of changes can

[99] Campbell Direct, pages 150-151
[100] Ibid, page 152
[101] Ibid, page 153

impact a capital project's completion timeline and; consequently, Xcel must adapt to changing conditions over the course of the year.[102] [103]

The Company stated that the Department's recommendations to update in-service dates and prevent the substitution of like projects during the test year conflict with the concept of a representative test year. Xcel explained that it understands the importance of some limitations on the projects included in the Step year; however, the 2014 test year in this case is fundamentally no different than the test year in a traditional rate case and moving away from this traditional treatment of representative test year costs undermines the test year concept. Additionally, Xcel opined that not allowing any flexibility in the second and third years of a plan provides a disincentive to utilities seeking to offer customers the benefits afforded by a multi-year approach.[104]

Xcel disagreed with the Department's recommendation and pointed out that that the shift of specific capital projects out of the 2014 test year and 2015 Step does not reflect a significant percentage of capital projects or capital expenditures, and the capital expenditures that have been *shifted out* of the 2014 test year and 2015 Step have been offset by other capital projects that are being *shifted into* the 2014 test year and 2015 Step. The Company explained that these replacement projects fall into one of three categories: (1) like-kind replacements, (2) emergent work, and (3) normal business changes. Like-kind replacements are new projects with work similar in scope, timing, and cost to the original projects. Emergent work refers to projects that were not originally planned for during the budgeting process (e.g., major break-fix projects, projects needed to be responsive to new regulatory requirements, etc.). Projects that fall into the normal business changes category are those that can be completed during year and replace other postponed or cancelled projects. Since these replacement projects allow the Company to operate within its budget, comply with regulatory requirements, and adapt to changing circumstances, Xcel believes that it is appropriate to allow for the replacement of delayed or cancelled 2014 capital projects.[105]

Department of Commerce – Surrebuttal Testimony

The Department argued that since the original filing included 733 capital projects for the 2014 Test Year and 116 for the 2015 Step Year, it would not be reasonable to expect that the Department and other parties in the case could review such new requests. Such an approach would not result in development of a reasonable basis for the Commission to set rates. The DOC stated that it is up to the Company to identify all capital projects with its initial rate case filing.[106]

The Department contended that, while it appreciates that facts may change over time, the Company has not shown why it cannot reasonably manage these changes for purposes of the rate

[102] Mills Rebuttal, page 19
[103] O'Connor Rebuttal, page 46
[104] Sparby Rebuttal, page 19
[105] Perkett Rebuttal, pages 38-42
[106] Campbell Surrebuttal, pages 105-106

case and added that, through a MYRP filing, Company has an opportunity to not only recover its traditional 2014 test year capital costs but also additional 2015 Step capital projects which adds 36 projects for a total of $579.9 million to rate base and $68.9 million in increased revenue requirements. The Department opined that with this new opportunity comes new responsibility to demonstrate the reasonableness of including recovery of its proposed projects in rates and described Xcel's position to be that it should not be required to demonstrate the accuracy of its claimed in-service dates for 2014 and 2015 capital projects that were in the initial petition.[107]

The Department reaffirmed its recommendations on this subject.

ALJ Report

The ALJ discussed the changes for in-service dates in Findings 480 through 501. Her analysis is found on Findings 494 through 500 and her recommendation is given in Finding 501:[108]

> 494. As discussed above, the Commission is required to set rates that allow the utility an opportunity to recover its costs of providing service, including depreciation of and a return on capital investments that are "used and useful" in providing service to ratepayers.
>
> 495. The Minnesota Supreme Court has held that utility property is "used and useful" when it: (1) is "in service"; and (2) is "reasonably necessary to the efficient and reliable provision of utility service."
>
> 496. Based this standard, the Administrative Law Judge concludes that the 2014 test year and 2015 Step should be based on the most current in-service dates for capital projects because otherwise the rates will include recovery of costs for projects that are not yet "used and useful."
>
> 497. Contrary to the Company's suggestion, the Commission's decision in the *Myer Shark* case does not command a different result. In that case, the Commission examined whether a refund should be issued to ratepayers for tax expenses that were included in the test year but ultimately were not incurred by the Company, and determined that no refund was necessary. The Commission reasoned that actual costs may differ from the test year, but the changes will be roughly symmetrical. The issue in that case was raised after the rates were established, not during a rate case when the features of the test year are being determined. Thus, the *Myer Shark* decision does not address the issue of what costs should be included in the test year, the matter that is disputed here.
>
> 498. In addition, while the Administrative Law Judge recognizes that the utility industry is a dynamic business and priorities change, the utility still has a legal obligation to demonstrate that its test year rate base and depreciation expense include projects that are used and useful. Projects that have been delayed do not meet this standard.

[107] Ibid, page 107
[108] ALJ Report, pages 112-113

499.With regard to the Company's proposal that it be allowed to substitute replacement projects for capital projects that have been delayed, the Administrative Law Judge concludes that the Company should only be allowed to substitute replacement projects when: (1) the Company has shown that the replacement projects are necessary, the costs are prudent, and the projects will be in-service during the test year; and (2) the other parties have had sufficient time to review the proposed replacement projects. The Administrative Law Judge concludes that such an approach is a reasonable compromise between the Company's position and the Department's position because it recognizes that a utility's capital plans are bound to change somewhat during the course of a long MYRP proceeding but also holds the Company to its burden of proof.

500. In Rebuttal Testimony, Company witness Lisa H. Perkett identified certain substitute projects for the 2014 test year. Inclusion of these projects would appear to decrease the Department's proposed revenue reduction from $2.18 million to $1.8 million for changes to in-service dates in 2014. No party disputed the need for these specific substitute projects or the costs. The Department, however, disputed the propriety of including substitute projects generally on the grounds that such projects would not be subject to adequate review by the parties. While ensuring the parties have adequate time to review the proposed new projects is important, in this case, the Department was provided the list of substitute projects on March 21, 2014 in response to an Information Request and these same projects are included in Ms. Perkett's Rebuttal Testimony filed in June 2014.

501. Based on the evidence in the record and for the reasons discussed above, the Administrative Law Judge recommends that the Commission reduce the Company's proposed 2014 test year revenue requirement and 2015 Step test year revenue requirement to reflect the updated in-service dates for projects included in the Company's initial filing, but also allow the substitution of the projects specified by Company witness Ms. Perkett in her Rebuttal Testimony.

Xcel – Exceptions to ALJ Report

Since the ALJ accepted both the Department's proposal to remove from rate base projects that would not be in service and Company's proposal to offset this rate base decrease with projects that will now be in service, Xcel stated that the ALJ's approach is reasonable and balances parties' interests.[109]

Department of Commerce – Exceptions to ALJ Report

The Department stated that, while it appreciated the ALJ Report's attempt to broker a compromise, the Report's approach is inconsistent with the ratemaking concept of a test year or the procedures in rate cases. Investigating a new utility proposal in rebuttal testimony would not

[109] Xcel Exceptions to ALJ Report, page 54

be feasible since typically there is not time for even one round of discovery to be issued between rebuttal and surrebuttal testimonies, given that the goal at that point in the proceeding is to narrow issues, not expand them and given the typical number of issues that typically need to be addressed. The DOC asserted that limiting the time for parties to investigate new proposals late in the proceeding effectively shifts the burden of proof of costs' reasonableness from Xcel to other parties.[110]

Decision Alternatives

Decision alternatives for Changes to In-Service Dates for Capital Projects (2014 and 2015 Step)

1. Allow inclusion of 2014 Test Year and 2015 Step Year replacement projects specified in Ms. Perkett's Rebuttal Testimony Schedule 11. (Xcel, ALJ)

2. Deny inclusion of all 2014 Test Year and 2015 Step Year replacement projects. (DOC)

(Note: The decision alternatives for this item correspond to alternative VII, K (1 and 2) on p. 44 of the deliberation outline.)

Reference to Record
DOC Direct: Campbell, page 150 starting at line 10
Xcel Rebuttal: Clark, page 15 starting at line 1
Xcel Rebuttal: Mills, page 19 starting at line 11
Xcel Rebuttal: O'Connor, page 46 starting at line 12
Xcel Rebuttal: Perkett, page 38 starting at line 6
Xcel Rebuttal: Sparby, page 15 starting at line 17
DOC Surrebuttal: Campbell, page 102 starting at line 13
Xcel Initial Brief: Starting on page 103
DOC Initial Brief: Starting on page 118
Xcel Reply Brief and Proposed Findings: Starting on pages 83 and 100, respectively
DOC Reply Brief: Starting on page 48
DOC Proposed Findings: Starting on page 89
ALJ Report: Findings 480-501, starting on page 110
Xcel Exceptions to ALJ Report: Starting on page 54
DOC Exceptions to ALJ Report: Starting on page 23

[110] Department of Commerce Exceptions to ALJ Report, page 26

Xcel's Interim Rate Proposal

PUC Staff: Bob Harding

Statement of the Issue

Should the Commission authorize Xcel to propose, in its thirty-day compliance filing, a netting or offset of its test-year interim rate revenue over-collections (i.e. its test-year interim rate refund obligation) against step-year interim rate revenue under-collections?

Relevant Statutes and Commission Orders

Interim rate refunds, Minn. Stat. § 216B.16, Subd. 3(c)

> If, at the time of its final determination, the commission finds that the interim rates are in excess of the rates in the final determination, the commission shall order the utility to refund the excess amount collected under the interim rate schedule, including interest on it which shall be at the rate of interest determined by the commission. ... If, at the time of its final determination, the commission finds that the interim rates are less than the rates in the final determination, the commission shall prescribe a method by which the utility will recover the difference in revenues between the date of the final determination and the date the new rate schedules are put into effect. ...

Final determination defined, Minn. Stat. § 216B.16, Subd. 2(g)

> For the purposes of this section, "final determination" means the initial decision of the commission and not any order which may be entered by the commission in response to a petition for rehearing or other further relief. The commission may further suspend rates until it determines all those petitions.

Multiyear Rate Plan Order

In its June 17, 2013 Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans,[111] the Commission stated that

- If the applicant seeks interim rates as part of its rate case, the Commission will direct the applicant to address how the collection and possible refund of interim rates could be implemented in conjunction with the multiyear rate plan rate adjustment. [Order, p. 10]

[111] In the Matter of the Minnesota Office of Attorney General-Antirust 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/M-12-587

- It is presumed that interim rates will be calculated based upon the rate case test year unless it is demonstrated to be reasonable to do otherwise. [Order, paragraph 5, p. 12]

- Regarding any proposal to establish new rates on an interim basis, an application for a multiyear rate plan must include or be accompanied by an explanation of how the utility proposes to collect and possibly refund interim rates in conjunction with the collection of and transition to the rates arising from a multiyear rate plan. [Order, paragraph 21, p. 14]

Xcel Energy (Xcel)

Compliance proposal related to interim rates - November 13, 2014
Reply comments - January 13, 2005

Xcel "proposes to calculate the interim rate refund by comparing the total interim rate revenue collected under [its] interim rate schedule to the total final rate revenues authorized for the 2014 Test Year and 2015 Step. In other words, [Xcel's] approach would net the total interim rate revenues collected against the aggregate of the two separate revenue requirements for these years ordered by the Commission for the period [Xcel's] interim rate schedule is in effect and then refund any excess amount to customers."

Xcel believes its proposal is consistent with the purpose and intent of the interim rate statute and the multiyear rate plan statute. Xcel does not believe the interim rate statute only applies to a single, one-year or twelve-month interim rate time period. For a variety of reasons, Xcel did not propose an interim step increase at the beginning of this rate case or later in the proceeding. Xcel believes the interim rate statute allows interim rates to remain in effect for the duration of the proceeding, however long it may take, and refunds (and perhaps surcharges) to be calculated on a prorated basis according to the test-year (and step, if applicable) based on the length of time interim rates have been in effect.

Xcel also believes its proposal

- meets the purpose of the two statutes by reducing the effect of regulatory lag while allowing for the extended length of time that was needed to review this case.

- allows Xcel to avoid charging its customers a second interim step increase which could potentially confuse consumers, complicate billing and destabilize Xcel's revenue stream.

- is complimentary to Xcel's goals and proposal for moderating the rate increase(s) that result from this proceeding.

Department of Commerce (Department)

Comments – January 13, 2015
Amended Comments – January 16, 2015

The Department believes the Commission has two alternatives. The first would be Xcel's approach which would net the test year and step period together and treat the "interim-rate period as one time period in which the revenues collected under the interim rates are compared to the total revenues collected under the two sets of rates for the test years 2014 and 2015."

The second alternative would treat "the two test years of 2014 and 2015 separately for purposes of determining the total refund to ratepayers. This approach would continue to charge interim rates based on the authorized interim rate increase of approximately $127,400,000 per year; however, under this option the over- and/or under-recovery of interim rates would be calculated separately for each year. For 2014, ratepayers would receive a refund based on the difference between the actual revenues and authorized revenues. The same would be true for 2015 if final rates are less than authorized interim rates. However, if final rates are higher in 2015 than authorized interim rates, then consistent with Minn. Stat. § 216B.16 (c), Xcel would be allowed to surcharge ratepayers for under-recovered revenues for the period between the date of the Commission's final rate determinations and the date new rate schedules are put into effect. Since new rates for 2015 will not be implemented on January 1, 2015, the recovery of under-recovered rates would only pertain to the few months between the date of final rate determination and the date new rate schedules are put into effect under this approach."

For purposes of determining the interim rate refund, the Department recommends the Commission consider each year in Xcel's multiyear rate plan as separate test years. The Department also recommends that the interim rate refund be determined by adding interest to the 12 monthly over collections during the year 2014, reduced by under-collections during the period March 24, 2015 (rather than May 8, 2015) through the date new rate schedules are put into effect. The Department believes Xcel should be compensated for the time it agreed to give up to give the Commission more time to make its decision. The Department did not make this argument for time Xcel gave up to give the ALJ more time to issue her report.

Office of Attorney General (OAG)

Comments – January 13, 2015
Reply Comments – January 23, 2015

OAG believes Xcel should clearly explain how it plans to apply and calculate the interim rate refund and be required to account for interest on any over-collection of interim rate revenue. OAG believes Xcel needs to calculate different interim refund factors for each year interim rates are collected (i.e. the test year and the step). OAG believes this is necessary for Xcel to be consistent with the method used in previous rate cases and to compensate ratepayers for the time value of their money. In addition, OAG does not believe Xcel should be allowed to collect interest (or a carrying charge) on any under-collection during the interim period.

OAG also argued that Xcel should not be allowed to change the level or amount of interim rates collected during this case regardless of Xcel's proposal for a multiyear rate plan.

OAG also argued against the Department's recommendation that the surcharge period (if there is a surcharge) be lengthened by moving the start of the surcharge period to March 24 from May 8, 2015. OAG believes Minnesota law prohibits the surcharge period from starting until the date of the Commission's final determination on (or about) May 8, 2015.

OAG also asked the Commission to limit its decision to the facts presented in this case despite the likelihood of this case setting a pattern for future MYRP filings. OAG suggested the Commission require all utilities in future MYRP rate filings to fully explain and commit to the interim rate plans and proposals in their initial MYRP filings.

Staff Comment

The main question the Commission may want (but is not required at this time) to decide is whether to give advance approval (provisional or otherwise) to Xcel's request to

> net the total interim rate revenues collected against the aggregate of the two separate revenue requirements for these years ordered by the Commission for the period Xcel's interim rate schedule is in effect and then refund any excess amount to customers.

The Department and OAG are opposed but do not agree on the date on which Xcel should be allowed to begin recovering the difference between interim and new, final (step year) rates.

The following table provides a comparison of Xcel's interim rates and revenue compared to a hypothetical 2014 test year and step year revenue requirements. Xcel may over-recover its revenue requirement in 2014 and under-recover in 2015.

Hypothetical MYRP over and under-collection of revenue requirement	Calendar year 2014-test year	Calendar year 2015–step year	Cumulative total in 2015-step year
Interim rates	$127,406,000		$127,406,000
ALJ recommended rate increase as interpreted by Xcel (as of Jan. 16, 2015)	$69,600,000	$121,700,000	$191,300,000
Interim rate refund of test year over-collection	$56,806,000		
Interim rate surcharge of step year under-collection (probably must begin no later than date of Commission final determination)			$63,894,000

Normally, the interim rate refund (or surcharge) plan is a compliance item proposed by the utility in the thirty-day compliance filing at the end of the rate case. Usually, the refund plan is fairly straightforward and is not disputed by the parties. However, because Xcel's November 13 compliance proposal is disputed, the Commission may want to give some indication of what kind of plan it would approve in advance of Xcel making a compliance filing at the end of this case.

The MYRP Order indicates interim rates should be based on the test-year rather than the test-year plus the step period. In making its decision, the Commission may want to consider the extent Xcel (and any other utility asking for a multiyear rate plan) should be allowed to update or change its request for interim rates a year or more into a proceeding after making its initial request and receiving approval for a certain level of interim revenue.

With respect to the point that this proceeding has lasted a long time, the MYRP statute provides for an extra 90 days because of the MYRP and the Commission is allowed an extra 90 days if there is more than one rate case pending. Xcel's two waivers of the statutory deadlines provided an extra eight to nine weeks in addition to the 180 days the Commission was entitled to under the statute.

Staff believes Xcel's argument about this "delay" causing regulatory lag would carry more weight if Xcel had not recently completed rate cases filed in 2010 and 2012 and was not continuing to recover significant amounts of cost and capital expenditures using riders.

With respect to the specific objections and points raised by the Department and OAG, staff notes that in its pro forma calculations, Xcel proposed a different factor for the test year and step rather than one combined factor for the entire period. If the Commission allows Xcel to net step period under-collection again its test-year refund obligation, Xcel's proposed methodology appears consistent with previous Xcel refund plans.

Staff does not believe the Department's proposal to move the date on which Xcel would be entitled to surcharge for any interim period under-collection ahead of the date of the Commission issuing its final determination is permitted under Minnesota law. Minn. Stat. § 16, subd 2 is very clear about the definition of the date of final determination being the date of the Commission's initial decision and not the date that the Commission could of made its decision absent other circumstances.

In addition, staff does not believe the interim rate statute requires the Commission to approve Xcel's request. The interim rate statute is very clear about the significance of the final determination and the Commission is not required to allow Xcel to collect the difference between interim and final rates until the date of the final determination.

> ... If, at the time of its <u>final determination</u>, the commission finds that the interim rates are in excess of the rates in the <u>final determination</u>, the commission shall order the utility to refund the excess amount collected under the interim rate schedule, including interest on it which shall be at the rate of interest determined by the commission. ... If, at the time of its <u>final determination</u>, the commission finds that the interim rates are less than the rates in the <u>final determination</u>, the commission shall prescribe a method by which the utility will recover the difference in revenues between the date of the <u>final determination</u> and the date the new rate schedules are put into effect. ... (Minn. Stat. § 216B.16, Subd. 3(c))

On the other hand, the Commission could interpret the interim rate statute to apply to all of Ch. 216B, section 16, including the multi-year rate plan statute and decide that the increase at the end of the case resulting from the MYRP filing, if higher than interim rates, takes effect at the time of the Commission's final determination, as defined in Ch. 216B, section 16. The interim rate refund statue is clearly and intentionally asymmetrical in its choice of effective dates for the interim refund obligation and the final rates if higher than interim rates.

Several additional points are worth noting. First, the revenue requirement the Commission authorizes for Xcel for the test-year and the step-year are likely to be different from what the ALJ recommended. If the rate increase in the test-year plus the step-year are less than $121.7 million than Xcel's request will probably be moot. However, if it is more than $121.7 million, the Commission could decide to allow Xcel to net the amount of the under-collection in the against the test-year refund obligation.

Staff does not believe the Commission needs to address specific details in Xcel's hypothetical proposal for calculating the refund or surcharge mechanism absent any exact numbers to work with. If the Commission does want to address this issue and provide guidance, staff believes it could generally address the MYRP netting question and whether the statute allows any flexibility with the respective to the date of the final determination as that terms relates to the interim rate statute.

Decision Alternatives

1. Authorize Xcel, in its thirty day compliance filing, to propose netting its test year interim rate revenue refund obligation against its step year interim rate revenue under-collections.

2. Do not authorize Xcel to propose netting its test year interim rate revenue refund obligation against its step year interim rate revenue under-collections.

3. Determine that in Xcel's multi-year rate plan, the date of the Commission's final determination does not control the date upon which the utility is allowed to recover the difference between interim rates and final (step year) rates. Determine the as of date on which Xcel may be allowed to recover the difference between interim and final (step year) rates is March 24, 2015.

4. Determine that in Xcel's multi-year rate plan, the date of the Commission's final determination is the date the Commission issues its initial decision regardless of circumstances and controls the date upon which the utility is allowed to recover the difference between interim rates and final (step year) rates.

(Note: The decision alternatives for this item correspond to alternative VII, L (1 through 4) on p. 45 of the deliberation outline.)

Interest Rate on Interim Rates Refund

PUC Staff: Jorge Alonso

Introduction

This issue is disputed between Xcel and the OAG. The Company proposed that the interest rate on any possible interim rate refund should not be higher than the prime interest rate. The OAG recommended that the Commission, as it did in Xcel's previous rate case, approve an interest rate equal to the Company's overall rate of return.

Note: Parties positions that repeat or reaffirm a previous position are not repeated; however, all references on the record for this subject are listed at the bottom of this section.

Party Positions

Xcel – Direct Testimony

Xcel proposed that, for purposes of refunding, the same refund mechanism used its 2011 electric rate case be used in this rate case.[112]

Office of Attorney General – Direct Testimony

The OAG pointed out that the prime rate does not compensate ratepayers who may be subject to credit card debt interest of up to 15% or higher and opined that, if the prime rate is used, NSP would be holding ratepayer funds at an unreasonably low cost. The OAG concluded that a higher rate is justified in these circumstances just as they were in NSP's last rate case and recommended usage of Xcel's full weighted cost of capital as the interest rate for refunds.[113]

Xcel – Rebuttal Testimony

Xcel pointed out that Interest on interim rates at the Prime Rate exceeds the Company's cost of replacement short term borrowing[114] and concluded that application of the Company's ROR to the entire refund would be inappropriate.[115]

---

[112] Clark Direct, page 26
[113] Lindell Direct, page 59
[114] Tyson Rebuttal, page 31
[115] Heuer Rebuttal, page 39

Xcel – Initial Brief

Xcel stated that, since the Company's cost of short term borrowing is 0.62% and the Prime Rate is 3.25%, it is clear that the Company the will pay far more in interest on interim rate refunds than it would cost for replacement short term borrowing. Xcel added that 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 and, 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.[116]

Office of Attorney General – Initial Brief

The OAG pointed out that the reasoning for awarding the larger interest rate in the last rate case applies to this case as well. The OAG mentioned that Xcel has requested the largest rate increase in the history of the state, and it was granted an interim rate in accordance with that request. But based upon the challenges presented by the OAG, the Department, and other intervenors, and the concessions that Xcel has made, it is very likely that Xcel's final rate will be substantially lower than the interim rate.[117] The OAG pointed out that, regarding the rate case's likely outcome, the Department noted, "[T]here's a similarity between the last case and this case . . . in that there is a large increase and a good percentage of that increase was being requested by the Department not to be granted."[118]

The Commercial Group (CG) – Initial Brief

The Commercial Group pointed out that, by setting the interim refund rate at NSP's overall cost of capital in the last rate case, the Commission corrected an unfairness (as perceived by the CG) whereby NSP had over-projected its revenue requirement for interim rates at least seven straight times while paying low interest on such over-collections. The CG saw no reason for the Commission to alter their conclusions from the last rate and supported the OAG's position that interim rate refunds accrue interest at the overall cost of capital set in this proceeding.[119]

---

[116] Xcel, Initial Brief, pages 106-107
[117] Office of Attorney General, Initial Brief, page 42
[118] Tr. Evid. Hearing, Volume 5, at 80–81 (Lusti)
[119] The Commercial Group, Initial Brief, pages 13-14

ALJ Report

The ALJ discussed the interest rate on a possible interim rate refund issue in Findings 968 through 985. Since authorizing a higher interest rate would necessitate a variance, the ALJ listed those requirements in Finding 969[120]:

969. Pursuant to Minn. R. 7829.3200 (2013), the Commission can vary its rules when it determines that the following requirements are met:

   i. Enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;
   ii. Granting the variance would not adversely affect the public interest; and
   iii. Granting the variance would not conflict with standards imposed by law.

In Findings 981 through 983, the ALJ addressed the three prongs mentioned in Finding 969:[121]

981. The third prong of Minn. R. 7829.3200 requires a finding that granting the variance would not conflict with standards imposed by law. Minn. Stat. § 216B.16, subd. 3, provides:

> If, at the time of its final determination, the commission finds that the interim rates are in excess of the rates in the final determination, the commission shall order the utility to refund the excess amount collected under the interim rate schedule, including *interest on it which shall be at the rate of interest determined by the commission*.

This statute gives the Commission the authority to determine the interest rate applied to any interim rate refund. Thus, granting the variance would not conflict with standards imposed by law.

982. The second prong of Minn. R. 7829.3200 requires a finding that "granting a variance would not adversely affect the public interest." Because the Company seeks to impose a carrying charge on its customers for nuclear refueling outage costs that is equal to its rate-of-return, grossed up for taxes, the Administrative Law Judge concludes that the public interest would not be adversely affected if the Company were required to pay that same rate on interim rate refunds. Both rates are essentially payments for the use of money. The Company has failed to explain how the public interest is served by the Company paying only 3.25 percent interest on the interim rate refund at the same time imposing a much higher rate on its customers as a carrying charge.

---

[120] ALJ Report, page 219
[121] Ibid, page 222

983.The first prong of Minn. R. 7829.3200 requires a determination that “enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule.”

The ALJ concluded the following and made a qualified recommendation:[122]

984.Based on the Commission’s decision in the last rate case, the Administrative Law Judge concludes that the determination of whether enforcement of the rule will impose an excess burden on ratepayers in this case depends largely on the magnitude of the over-collection of interim rates, if any, in this case. If the amount of over-collection is comparable to the last case, then the reasoning in the Commission’s 12-961 ORDER would apply equally to this case given the magnitude and frequency of the over-collections by the Company. On the other hand, if the over-collection is a much smaller amount, the burden on ratepayers from lending the Company funds at the 3.25 percent Average Prime Rate may not be excessive.

985.Therefore, a final determination on the first prong can only be made by the Commission after it makes the revenue requirement decisions in this case.

Staff Analysis

Based on Xcel’s January 9, 2015 compliance filing of revised financial and rate design schedules based on the ALJ’s Report, the Company calculates that, should the Commission adopt all recommendations, its revenue deficiencies for 2014 and 2015 would be $74.067 million and $196.458 million, respectively. The Commission’s January 2, 2014 Order accepting the Company’s filing and suspending rates authorized Xcel to annually collect $127.406 million.

Based on that information, Staff calculates that Xcel would have *over*-collected $53.339 million during all of 2014 ($4.44 million per month). Based on the same numbers, Xcel also began *under*-collecting $5.754 million per month ($196.458 million minus $127.406 million divided by twelve) in January 2015.

Parties so far have proposed two possible alternatives for the applicable interest rate – Prime or the Company’s ROR. Staff would like to introduce a hybrid alternative for the Commission to consider – have the Company’s ROR apply to all amounts twelve months and older and have the Prime Rate apply to all other amounts. Staff believes that this alternative takes into account all the parties’ positions and arguments and provides a more balanced approach to the dispute.

Finally, Staff points out that Xcel’s Monticello prudence review[123] final outcome could have a material impact on this case’s revenue requirement; however, the outcome in that docket was still unknown at the time these briefing papers were written. Regardless of Monticello’s and other Commission decisions’ combined revenue requirement impact, Staff believes that Xcel will

[122] Ibid, pages 222-223
[123] Docket E-002/CI-13-754

still owe ratepayers a refund for 2014. Procedurally, Staff's proposed hybrid alternative can still be used to calculate interest on the possible refund.

Decision Alternatives

Decision alternatives for Interest Rate on Interim Rates Refund

1. Determine that the appropriate interest rate to be paid on a possible interim rate refund should be the prime interest rate, or 3.25%. (Xcel, ALJ – if refund amount is not large)

2. Determine that the appropriate interest rate to be paid on a possible interim rate refund should be based on the Company's rate of return[124]. (OAG, CG, ALJ – if refund amount is large)

3. Determine that the appropriate interest rate to be paid on over-collections older than twelve months should be based on the Company's rate of return and, conversely, the appropriate interest rate to be paid on over-collections than twelve months old should be the prime interest rate, or 3.25%. (Staff)

(Note: The decision alternatives for this item correspond to alternative VII, M (1 through 3) on p. 45 of the deliberation outline.)

Reference to Record
Xcel Direct: Clark, page 26 starting at line 4
OAG Direct: Lindell, page 58 starting at line 8
Xcel Rebuttal: Heuer, page 37 starting at line 6
Xcel Rebuttal: Tyson, page 31 starting at line 17
Xcel Initial Brief: Starting on page 106
OAG Initial Brief: Starting on page 40
CG Initial Brief: Starting on page 13
Xcel Reply Brief and Proposed Findings: Starting on pages 86 and 103, respectively
OAG Reply Brief: Starting on page 4
OAG Proposed Findings: Starting on page 26
ALJ Report: Findings 968-985, starting on page 218
OAG Exceptions to ALJ Report: Starting on page 19

[124] The rate of return will be based on the return on equity (ROE) approved in this rate case.

Fuel Cost Recovery Reform

PUC Staff: Jorge Alonso

Introduction

This issue is disputed between Xcel, the Minnesota Chamber of Commerce (MCC or the Chamber) and Xcel Large Industrials (XLI). The Department also provided testimony on this issue.

The disagreement between the parties is whether the rate case or the FCA is the appropriate forum for discussion of fuel clause reform.

Note: Parties positions that repeat or reaffirm a previous position are not repeated; however, all references on the record of this subject are listed at the bottom of this section.

Party Positions

Minnesota Chamber of Commerce – Direct Testimony

The Minnesota Chamber of Commerce pointed out that current fuel costs of $836 million represent 30% of the Company's $2.78 billion revenue and all those costs are recovered through the fuel cost rider on a monthly basis.[125]

The MCC observed the following[126]:

1. Recovery of replacement power costs due to planned and forced outages: At present, Xcel automatically recovers the replacement power costs due to planned and forced outages through the fuel cost adjustment. This arrangement is concerning as it places all the risk on customers and little incentive for Xcel to be efficient in the management and maintenance of its plant operations. While the fuel costs are subject to review through the AAA proceedings, the review occurs after a very long regulatory lag (year or greater) at which point it becomes difficult to ascertain prudency.

2. Burden of proof on customers and not the utility: Since the utility recovers the costs as they occur, the burden of proof shifts to customers to prove after the fact if certain costs were imprudently incurred or not.

3. Unintended consequence of minimizing on costs fixed in base rates and limited motivation to manage fuel costs due to automatic recovery: As noted by the DOC in the AAA proceedings (docket 12-757), the automatic fuel cost recovery provides the perverse incentive to minimize on O&M costs (present in base rates) in between rate

[125] Maini Direct Testimony, page 41
[126] Ibid, pages 41-42

cases at potentially the expense of not managing fuel efficiently (see DOC comments in 12-757, page 18)

The Chamber also noted that the issues related to the burden of proof falling on customers and the automatic recovery of fuel and replacement power costs due to planned and unplanned outages are common to all utilities.

Based on the lack of progress in the AAA docket, the Chamber considered the current rate case proceeding seems to be a reasonable forum to advance the issues and concerns surrounding fuel costs.[127]

Xcel Large Industrials – Direct Testimony

XLI stated that, in theory, NSP is required to demonstrate that the costs recovered in the FCR are both prudent and reasonable. It does so by filing an annual report with the Department of Commerce (Department). The Department then reviews the report and submits its findings to the Commission. Based on the Department's findings and other evidence (such as comments filed by the utilities), the Commission can then determine whether NSP's fuel costs are prudent and reasonable. XLI added that, in reality, fuel issues are highly complex, and a thorough analysis requires a significant time and personnel commitment. By the time the review is completed and the Commission has acted, the costs will have already been collected from customers in the distant past. Given the complexity and the passage of time, the current process affords little or no risk of a fuel cost disallowance as a result of major plant outages.[128]

XLI offered the review of the 2010-2011 (FYE11) AAA Reports as an example. In that instance, the Department made three recommendations to disallow a total of $721,700 of increased energy costs incurred during plant outages; however, the Commission declined to act on the Department's recommendations but mentioned that prudence of costs related to the forced outages remain subject to review by the Commission at a future date.[129] XLI countered by saying that, given the complexity of the AAA Reports and the fact that the costs at issue were recovered in rates over three years ago, it will be even more challenging for the Department to provide the details sufficient to allow the Commission to make specific findings. In its Response Comments filed in Docket No. E999/AA-11-792, the Department stated that it had spent ten months reviewing the AAA reports and following-up with the utilities. As subsequent AAA reports have been filed, and given the Department's limited resources and the passage of time, it is unclear whether the Department's recommendations on FYE11 cost disallowances can receive further consideration.[130]

[127] Ibid, page 42
[128] Pollock, Direct Testimony, pages 25-26
[129] Ibid, pages 26-27
[130] Ibid, page 27

XLI reasoned that the status quo is no longer just and reasonable and recommended that a new FCR design should be presented in NSP's next rate case or within 90 days of the Commission's final order in this case, whichever is earlier.[131]

XLI finished by adding that the revised FCR must:[132]

- Establish an effective incentive for NSP to control both fuel and purchased energy costs in a manner that results in overall savings for customers;

- Avoid causing chronic over- or under-recovery without necessarily guaranteeing dollar-for-dollar recovery;

- Emphasize that the burden of proof is on NSP to show that costs recovered are just and reasonable; and

- Allow for administratively efficient review of fuel and purchased energy costs by the Department, the Commission, and customers.

Xcel Energy – Rebuttal Testimony

Xcel pointed out the Company did not include fuel costs in its calculation of base rates for our multi-year rate plan. As a result, any change in how these costs are recovered will not impact the revenue requirement calculations provided in this case.[133]

Xcel also noted that the Department held a meeting on November 8, 2013 to address issues brought up by the Chamber and the XLI. Given that these discussions have commenced in the AAA docket, the Company stated that it would be beneficial to continue them in that docket. Moreover, because these issues are not unique to the Company, the AAA docket is the best forum to ensure that all interested Parties are present.[134]

Department of Commerce – Rebuttal Testimony

The Department stated that the current FCA Rider mechanism allows Xcel's cost of fuel and purchased power costs to be automatically passed through to ratepayers. As such, the current recovery mechanism dilutes Xcel's incentives to minimize energy costs. The DOC added that there are no explicit incentives for Xcel to mitigate these energy costs when they are simply passed through to ratepayers. Additionally, it is difficult to demonstrate after-the-fact whether these energy costs were prudently incurred costs.

The Department discussed that a well-designed incentive mechanism would encourage utilities to minimize energy costs and that such mechanism should ensure that Xcel internalizes its total

[131] Ibid, page 30
[132] Ibid, page 32
[133] Robinson Rebuttal Testimony, page 25
[134] Clark Rebuttal Testimony, page 42

cost of doing business, including its fuel and replacement power costs during outages. Under such an incentive mechanism, Xcel would have the appropriate incentives to keep total costs as low as possible because it would be in Xcel's own best interest to do so.

Since this subject is important to *all* electric utilities, the Department recommended that it would be better addressed in the AAA docket; however, the DOC stated that it is important to consider the matter in the near future.[135]

Minnesota Chamber of Commerce – Surrebuttal Testimony

The Chamber acknowledged the merit of addressing the matter in the AAA docket; however, the MCC expressed concern regarding the fact that there is no clear timeline to resolve this issue. For that reason the Chamber recommended that, if no resolution occurs by the time Xcel files its next rate case, the Company should be ordered to provide a new FCA structure.

Xcel Large Industrials – Surrebuttal Testimony

XLI stated that fuel clause reform has already been discussed at length in the AAA dockets without resolution, narrowing of the issues or achieving a common understanding. Further, inviting all utilities and interested parties to discuss reform in the AAA docket would significantly diminish the likelihood that a consensus would ever be reached among parties having widely diverse interests. For these reasons, XLI considers it appropriate for the Commission to address FCR reform on a utility-specific basis and, thus, reasserted its initial recommendation.[136]

Minnesota Chamber of Commerce – Initial Brief

The Chamber mentioned that intervening parties' concerns stem in part with there being no incentive to manage costs prudently and no penalty if not done. Xcel therefore, has no incentive to add oversight and risk of no return, delay is good for Xcel. There is no deadline or motivation for the Company to move this forward, so the Commission needs to provide one in an order.[137]

ALJ Report

The ALJ discussed the Fuel Clause Adjustment Reform in Findings 986 through 999. The ALJ recommended that, because the FCA involves all electric utilities in the state, any possible reform should be addressed in the AAA docket. The ALJ gave her recommendation in Finding 999:[138]

> 999. XLI, MCC, and the Department all raise valid concerns regarding the current FCA mechanism and the need for reform. The Administrative Law Judge concludes, however,

[135] Ouanes Rebuttal Testimony, pages 12-13
[136] Pollock, Surrebuttal Testimony, pages 33-34
[137] Minnesota Chamber of Commerce, Initial Brief, page 29
[138] ALJ Report, page 225

that FCA reform and proposals for a new incentive-based FCA mechanism are properly part of the AAA docket because the issues involve all electric utilities operating in the state. The Administrative Law Judge encourages the Commission to address reformation of the FCA in a timely fashion in order to meet the needs of interested stakeholders.

Decision Alternatives

Decision alternatives for Fuel Cost Recovery Reform

1. Determine that Fuel Cost Recovery Reform decisions should be made in the AAA docket. (Xcel, ALJ)

2. Require the Company to propose a new FCA mechanism in the next rate case or within 90 days of the Commission's order in this rate case, whichever is sooner. (XLI)

3. Require the Company to propose a new FCA structure that addresses concerns raised in this rate case if the matter has not been resolved in the AAA docket by the time Xcel files its next rate case (MCC)

(Note: The decision alternatives for this item correspond to alternative VII, N (1 through 3) on p. 46 of the deliberation outline.)

Reference to Record
MCC Direct: Maini, page 41 starting at line 12
XLI Direct: Pollock, page 25 starting at line 1
Xcel Rebuttal: Clark, page 42 starting at line 9
Xcel Rebuttal: Robinson, page 25 starting at line 10
DOC Rebuttal: Ouanes, page 11 starting at line 14
MCC Surrebuttal: Maini, page 26 starting at line 21
XLI Surrebuttal: Pollock, page 33 starting at line 1
Xcel Initial Brief: Starting on page 108
DOC Initial Brief: Starting on page 264
MCC Initial Brief: Starting on page 29
XLI Initial Brief: Starting on page 10
Xcel Reply Brief and Proposed Findings: Starting on pages 89 and 105, respectively
DOC Proposed Findings: Starting on page 194
MCC Reply Brief: Starting on page 12
ALJ Report: Findings 986-999, starting on page 223
XLI Exceptions to ALJ Report: Starting on page 9

Sherco 3 Outage – Replacement Fuel Costs

PUC Staff: Jorge Alonso

Introduction

The issue is disputed between Xcel and the Minnesota Chamber of Commerce (MCC or the Chamber).

This issue is not very contentious and the ALJ does a good job of summarizing the parties' positions; therefore, the ALJ's findings are used to summarize parties positions.

ALJ Report

The ALJ discussed the changes for in-service dates in Findings 567 through 571[139]:

567. In November 2011, the Sherburne County Generating Station (Sherco) coal-fired power plant experienced a catastrophic failure of Unit 3, resulting in a reduction of the plant's power generating capacity. As a result, the Company was required to purchase replacement power to cover the deficit created by the outage in Unit 3. According to the Department, from November 2011 to October 2012, $22.7 million in additional power costs were incurred as a result of the extended outage of Unit 3. The Company has sought recovery of the replacement power costs through the Fuel Clause Adjustment mechanism rather than through base rates.[140]

568. The issue of recovery for Sherco Unit 3 replacement power costs has been discussed in the AAA proceedings before the Commission, in Docket No. E999/AA-12-757 and Docket No. E999/AA-13-599.[141] The Company filed an extensive report in Docket No. E999/AA-13-599 discussing the cause of the Sherco Unit 3 failure.[142]

569. MCC has also raised the issue in this case. Specifically, MCC recommended that the replacement power costs from the Sherco Unit 3 outage be capitalized and recovered over the life of the power plant.[143] According to MCC, the replacement power costs from the Sherco Unit 3 outage should be recovered from future ratepayers who will benefit from the reconstruction and increased capacity of Sherco Unit 3 as a result of the failure in 2011, not current ratepayers.[144]

---

[139] ALJ Report, pages 132-133
[140] Clark Rebuttal Testimony, page 44
[141] Lusti Direct Testimony, pages 67-68
[142] Schedin Direct Testimony, page14
[143] Ibid, pages 13-14
[144] Ibid, page 14

570.The Department disagreed with MCC and recommended that the issue of replacement power costs from the Sherco Unit 3 outage be addressed as part of the AAA docket.[145]

571.The Company also believes the issue of replacement power cost recovery should be addressed as part of the AAA docket.[146] [147] The Company asserted that replacement power costs should not be capitalized because the cost of power should be borne by the customers who used the power during the Sherco Unit 3 outage.

The ALJ's recommendation was given in Finding 572:[148]

572.Because replacement power costs are for power that was used during the outage of Sherco Unit 3, the Administrative Law Judge concludes that the issue of cost recovery is properly addressed as part of the AAA docket.

Decision Alternatives

<u>Decision alternatives for Sherco 3 Outage – Replacement Fuel Costs</u>

1. Find that recovery of the Sherco 3 Outage's Replacement Fuel Costs should be addressed in the AAA docket . (Xcel, ALJ)

2. Find that recovery of the Sherco 3 Outage's Replacement Fuel Costs should be addressed in the this docket and order that these costs be capitalized and recovered over the life of the plant. (MCC)

(Note: The decision alternatives for this item correspond to alternative VII, O (1 and 2) on p. 46 of the deliberation outline.)

<u>Reference to Record</u>
DOC Direct: Lusti, page 67 starting at line 10
MCC Direct: Schedin, page 12 starting at line 13
Xcel Rebuttal: Anderson, page 4 starting at line 1
Xcel Rebuttal: Clark, page 44 starting at line 1
Xcel Rebuttal: Perkett, page 54 starting at line 1
MCC Surrebuttal: Schedin, page 9 starting at line 14
Xcel Initial Brief: Starting on page 108
MCC Initial Brief: Starting on page 5
Xcel Reply Brief and Proposed Findings: Starting on pages 89 and 105, respectively
MCC Reply Brief: Starting on page 1
ALJ Report: Findings 567-572, starting on page 132

---

[145] Lusti Direct Testimony, page 68
[146] Clark Rebuttal Testimony, page 44
[147] Anderson Rebuttal Testimony, page 4
[148] ALJ Report, page 133

Black Dog Units 2 and 5 Outage Costs

PUC Staff: Jorge Alonso

Introduction

The issue is disputed between Xcel and the Xcel Large Industrials (XLI).

XLI proposed disallowance of outage costs related to Black Dog 2 and 5. The Company argued that those costs occurred outside the 2014 test year, were not included in this rate case and to disallow them would be inconsistent with test year principles.

Since both parties agree that replacement power costs related to the outage should be addressed in the FCA docket, that discussion along with parties' positions that repeat or reaffirm a previous position are not repeated; however, all references on the record of this subject are listed at the bottom of this section.

Party Positions

XLI – Direct Testimony

XLI stated due to the Black Dog outage, the Company incurred additional capital costs of $24,104 and O&M expenses of $1.838 million (Total Company). XLI concluded that since the outage was the result of human error, the additional capital costs should be excluded from the rate base and the O&M costs incurred should be excluded from any consideration in setting the proper O&M expenses in this proceeding. XLI also recommended that any replacement fuel costs should also be disallowed in the annual automatic adjustment proceeding. [149]

Xcel – Rebuttal Testimony

Xcel disagreed with XLI's recommendations and stated that XLI is seeking disallowance of costs that were incurred outside of the test year[150] and that are not included in this rate case. To penalize the Company at this time for an event that occurred and was paid for prior to the rate case would be punitive and would be inconsistent with the principle of setting rates based on future costs rather than past costs.[151]

The Company added that the existence of human error should not automatically result in a disallowance and that despite Xcel's efforts to minimize human error, the Company

[149] Pollock Direct Testimony, pages 23-24
[150] Heuer Rebuttal Testimony, page 35
[151] Mills Rebuttal Testimony, page 16

acknowledges that total elimination is impossible.[152] Furthermore, the Company postured that XLI's position would hold it to a standard of perfection since XLI would impose a disallowance anytime there is "human error" involved in a cost and such a standard is inconsistent with the standard of prudence applied to the utility's actions.[153]

ALJ Report

The ALJ discussed the Black Dog Outage Costs in Findings 573 through 578[154] and her recommendation is given in Finding 579:[155]

> 579.Based on the above determinations, the Administrative Law Judge recommends that the Commission not adopt XLI's proposed disallowances in the 2014 test year for the 2012-2013 outage at Black Dog. With regard to whether any replacement fuel costs should be disallowed, that issue is properly addressed in the AAA proceeding.

Decision Alternatives

<u>Decision alternatives for Black Dog Units 2 and 5 Outage Costs</u>

1. Determine that no disallowance for investments or operating costs is needed. (Xcel, ALJ)

2. Disallow $24,104 for investments and $1.84 million for operating costs. (XLI)

(Note: The decision alternatives for this item correspond to alternative VII, P (1 and 2) on p. 46 of the deliberation outline.)

<u>Reference to Record</u>
XLI Direct: Pollock, page 23 starting at line 7
Xcel Rebuttal: Clark, page 44 starting at line 1
Xcel Rebuttal: Heuer, page 35 starting at line 1
Xcel Rebuttal: Mills, page 15 starting at line 5
Xcel Initial Brief: Starting on page 115
Xcel Reply Brief and Proposed Findings: Starting on pages 99 and 112, respectively
XLI Reply Brief: Starting on page 8
ALJ Report: Findings 573-579, starting on page 133

[152] Ibid
[153] Ibid, pages 18-19
[154] ALJ Report, pages 112-113
[155] Ibid, page 113