Rebuttal Testimony and Schedules
Lisa H. Perkett

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-12-813
Exhibit___(LHP-2)

Depreciation
Retirement and Removal Costs
Asset Retirement Obligations

August 12, 2013

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lisa H. Perkett. I am the Director of Capital Asset Accounting for Xcel Energy Services Inc., which provides services to Northern States Power Company (the Company).

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I provided Direct Testimony supporting the level of depreciation and nuclear decommissioning expense included in the 2013 test year. Specifically, I provided information on remaining lives, net salvage rates, and depreciation expense for all Company assets used in providing electric service and support for the Company's recommendation regarding nuclear decommissioning accruals.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to the Direct Testimony of Mr. Michael Majoros, Jr. Specifically, I respond to his assertions that the Company is not complying with the terms of the Settlement approved by the Commission in Case No. PU-07-776 and explain how Mr. Majoros' recommendations related to financial reporting conditions and retirement and removal cost recovery are inconsistent with the Settlement.

I also respond to Mr. Majoros' testimony regarding removal costs, explaining our methodology for determining removal costs and how recovery of those costs is consistent with the Settlement.

Further, I respond to Mr. Majoros' assertion that the Company is only required to remove assets that are subject to financial reporting requirements. I explain that the financial reporting requirements are based on legally defined Asset Retirement Obligations (legal AROs), which represent only a small portion of removal costs the Company must incur upon asset retirement. Similar arguments were made by Mr. Majoros in Case No. PU-07-776 and were rejected in the Settlement. Mr. Majoros' legal ARO arguments are inconsistent with the Settlement and customer interests, as demonstrated by long-standing regulatory practices in North Dakota, at FERC, and in every other regulatory jurisdiction the Company serves.

In addition, I respond to the following issues raised by Mr. Majoros:

- the removal cost estimate for Account 364, Distribution Poles;
- the recommendation for an amortization of the depreciation reserve surplus; and
- the claim that the Company did not properly inform the Commission of our nuclear decommissioning filings.

II. COMPLIANCE WITH SETTLEMENT

Q. WHAT COMMITMENTS DID THE COMPANY MAKE CONCERNING DEPRECIATION PRACTICES IN THE COMMISSION APPROVED SETTLEMENT IN CASE NO. PU-07-776?

A. The portion of the Settlement related to depreciation stated:

> The Company's proposed depreciation expense in this case was based on a uniform depreciation expense for use in all jurisdictions. In its testimony and post-hearing briefs, Staff challenged the reasonableness of the Company's methodologies in several respects.

In response, the Parties agree to the following process for establishing depreciation expenses:

- The Company will use the principles adopted in this Settlement Agreement in establishing depreciation rates for use in North Dakota. The Company will reflect its North Dakota depreciation rates in its annual North Dakota earnings reports and will file depreciation rates consistent with these principles as part of the Company's next electric rate case.

- For informational purposes, the Company will submit to the Commission the various depreciation studies and related documents that are periodically filed with the Minnesota Public Utilities Commission. Such filings include: Annual Review of Remaining Lives, Average Service Life and Vintage Group Filing (every five years), Triennial Review of Nuclear Decommissioning

- Ninety days before filing its next electric rate case, the Company will report to the Commission on whether it intends to propose North Dakota specific depreciable lives for distribution facilities, and the reasons for its proposal.

- Both Parties agree that, unless directed otherwise by the Commission, rate recovery – past, present, and future – for the removal and retirement of Company utility property will be used solely for the retirement of the Company's utility property and recognized as a regulatory liability.

Q. WHAT WERE "THE PRINCIPLES ADOPTED IN THE SETTLEMENT AGREEMENT FOR ESTABLISHING DEPRECIATION RATES FOR USE IN NORTH DAKOTA?"

A. The following principles for determining depreciation expense were adopted in the Settlement:

- Extend the service lives of the Sherco Generating Station, and five other combustion plants (Angus C. Anson, Granite City, High Bridge, Inver Hills, and Key City) as proposed by Staff. The Company will reflect the longer service lives in final rates implemented in this docket. The adjustment reduces the revenue requirement by $1,362,000.

- Reduce the depreciation rates for its transmission and distribution assets to effect an adjustment in the reserve balance, thereby recalibrating the balance to be more in line with theoretically calculated levels. This adjustment reduces the revenue requirement by $1,180,000.

- Recover removal costs in depreciation rates for transmission and distribution based on a net present value methodology rather than on a future cost methodology (using Staff's alternative five year historical average for the purposes of this case). This adjustment reduces the revenue requirement by $437,000.

- The parties recognize that the life extension has already been approved for the Monticello nuclear generating plant and that this fact eliminates the need for continued accruals to the existing escrow account, as reflected in the revenue requirement in this rate case. The parties also agree to return, effective beginning March 1, 2009 and completed by the end of 2012, the amounts that North Dakota customers contributed to the decommissioning escrow account for the Monticello plant. This provision of the Amendment reduces both the revenue deficiency for final rates and the Settlement Agreement amount by $212,000. Because this provision applies only to final rates (effective after March 1, 2009), it results in no change to the interim rate refund in this proceeding.

In all other respects, the Parties recommend that the Commission approve the methodologies used by the Company in this proceeding.

Q. HAS THE COMPANY COMPLIED WITH EACH OF THESE PRINCIPLES AND REQUIREMENTS?

A. Yes.

Q. PLEASE RESPOND TO MR. MAJOROS' ASSERTION THAT THE COMPANY VIOLATED THE TERMS OF THE SETTLEMENT BY NOT INCLUDING "DEPRECIATION RATES" IN ITS 2011 AND 2012 EARNINGS REPORTS.

A. The obligation is for the Company to "reflect its North Dakota depreciation rates in its annual North Dakota earnings reports." The depreciation expense and accumulated depreciation included in our earnings reports do reflect our North Dakota depreciation rates, thus we have complied with the Settlement provision. While we do not believe including the actual depreciation rates would be meaningful in the context of our earnings reports, we could provide that information if the Commission would like us to do so. Provided as Exhibit___(LHP-2), Schedule 1 is a list of our proposed North Dakota depreciation rates so that the Commission can determine whether the Company should provide this additional information in our earnings reports.

Q. PLEASE RESPOND TO MR. MAJOROS' ASSERTION THAT ALL FUTURE EARNINGS REPORTS SHOULD INCLUDE NORTH DAKOTA SPECIFIC DEPRECIATION RESERVES APPROVED IN THIS PROCEEDING AND MAINTAIN AND UPDATE THOSE RESERVES WITH NORTH DAKOTA-SPECIFIC ANNUAL ACTIVITY.

A. We are already providing North Dakota specific depreciation reserves in our earnings reports and will continue to do so. The Company uses a North Dakota specific depreciation study to determine North Dakota depreciation rates, and we have separately maintained a North Dakota specific depreciation reserve based on the depreciation rates from the 2007 proceeding. The depreciation reserve presented in the 2007 proceeding was a forecasted amount. The Commission does not specifically approve the reserve amount, but the depreciation rates approved by the Commission in this case will determine the actual expense going forward and accumulate in the North Dakota specific depreciation reserve. We will continue to present this information in our earnings reports.

Q. PLEASE RESPOND TO MR. MAJOROS' ASSERTION THAT THE COMPANY DID NOT COMPLY WITH THE NINETY-DAY NOTICE REQUIREMENTS CONTAINED IN THE SETTLEMENT, AND HIS REQUEST FOR A NORTH DAKOTA SPECIFIC DEPRECIATION STUDY.

A. The Company complied with the notice requirement. The provision requiring the Company to report to the Commission on whether it intends to propose North Dakota specific depreciable lives for distribution facilities – and the reasons for such a proposal – applied to the "next rate case," which was Case PU-10-657. We submitted a letter to the Commission prior to our 2010 rate case indicating we did not intend to proposed any changes to the depreciation lives and rates approved in the 2007 Settlement. The letter is provided as Exhibit___(LHP-2), Schedule 2.

Regarding Mr. Majoros' request for a North Dakota specific depreciation study, we completed a North Dakota specific depreciation study for transmission, distribution, and general assets in 2012. We filed the new study as Exhibit___(LHP-1), Schedule 7 to my Direct Testimony and used the new study and rates to determine the depreciation expense in this proceeding.

Q. WHAT OTHER SETTLEMENT PROVISION DOES MR. MAJOROS CLAIM THE COMPANY DID NOT FOLLOW?

A. Mr. Majoros asserts that the Company did not comply with the following provision:

> Both Parties agree that, unless directed otherwise by the Commission, rate recovery – past, present, and future – for the removal and retirement of Company utility property [a] <u>will be used solely for the retirement of the Company's utility property</u> and [b] <u>recognized as a regulatory liability</u>.

Q. DID THE COMPANY COMPLY WITH THIS PROVISION?

A. Yes. Our depreciation rates reflect the cost of removal and retirement in accordance with the Settlement, and the funds received for that purpose have been and will be used solely for removal and retirement purposes.

Q. WHAT WAS THE PURPOSE OF THIS PROVISION OF THE SETTLEMENT?

A. The purpose of the language in the Settlement was to provide assurance that the Company would spend what it recovers for removal in its depreciation rates on removal of the assets. This obligation applies to amounts recovered and accumulated through rates from customers. The accumulated amount is recognized as a regulatory liability, and included as an offset to rate base as part of the depreciation reserve for rate making. This regulatory liability is referred to as a non-legal ARO. The Company has been allowed to recover the removal costs of its assets as part of the depreciation expense over the operating period of those assets. This process remains unchanged by the financial reporting requirements for legal AROs.

Q. PLEASE RESPOND TO MR. MAJOROS' ASSERTION THAT THE COMPANY VIOLATED THE SETTLEMENT BECAUSE THE COMPANY DID NOT INCLUDE IN ITS FINANCIAL REPORTS THE REGULATORY LIABILITY FOR NON-LEGAL AROS.

A. The Company is required by the Settlement to create a regulatory liability for its non-legal AROs, and it has done so. Mr. Majoros recognizes that the Company has recorded a regulatory liability of $463 million on a total Company basis. He also states "the Company notes that the amounts related to the regulatory liabilities are based on regulatory orders and/or approved rates and the detail underlying these amounts can be seen on page 82 of our 2011 SEC Report 10-K." The information in our 10-K reflects our compliance with the regulatory liability provisions of the Settlement.

Q. HOW DO YOU RESPOND TO MR. MAJOROS' ASSERTION THAT THE COMPANY VIOLATED THE SETTLEMENT BECAUSE THE COMPANY INCLUDES IN ITS DEPRECIATION RATES THE REMOVAL COSTS OF ALL ASSETS, AND NOT JUST THOSE FOR LEGAL AROS?

A. The Settlement agreement provides "In all other respects, the Parties recommend that the Commission approve the methodologies used by the Company in this proceeding." One of those methodologies is the recovery of removal and retirement costs for all assets. As I will discuss in detail later in my testimony, legal AROs represent only a small portion of the actual costs the Company will incur for asset removal, and thus do not represent the appropriate level of removal costs for ratemaking purposes.

III. REMOVAL COST DETERMINATION

Q. HAS MR. MAJOROS IDENTIFIED ERRORS IN THE DEPRECIATION STUDY WITH RESPECT TO RETIREMENT AND REMOVAL COSTS?

A. No. While Mr. Majoros claims the Company is using the wrong method for determining the cost of removal, he does not identify any assets for which removal costs are being recovered that are not justified.

Q. PLEASE DISCUSS THE METHODOLOGY USED TO DETERMINE THE COMPANY'S PROPOSED NET SALVAGE RATES.

A. Net salvage percentages are based on the actual removal done in current dollars divided by the original cost of the retirement that generated the removal. While Mr. Majoros concludes that a net salvage percent recommendation must be based on the "old inflated cost approach," which is prohibited by the Settlement, our removal cost estimation process does not take current costs and inflate them to future periods. Rather, the determination of the net salvage rates simply assumes that an asset built in today's dollars will incur removal costs in the future based on the historical removal costs/investment costs relationship for similar previous assets. Our review of the historical removal cost relationship includes an operational review of the trended results to assure the chosen rate is appropriate. That is, if historically, the cost of removal for a type of asset is equal to 10 percent of the initial investment cost, then we use a 10 percent removal cost for newly acquired assets.

Q. DID THE COMPANY PROPOSE A FIVE-YEAR HISTORICAL COST METHOD FOR ITS EXPECTED COSTS OF REMOVAL IN THE CURRENT DEPRECIATION STUDY?

A. No. The five-year historical method was used to determine the change in depreciation expense in the 2007 Settlement. The Settlement does not require that the five-year historical method be used to set removal costs going forward, nor do we believe that method should be used. The five-year historical method can fluctuate based on the experience in those five years. For example, if there is an extreme weather event in one of those five years, this method may exaggerate the removal cost component in the depreciation rate. Thus, a method that smoothes these effects, such as the one we proposed, eliminates the fluctuations from one study to the next.

Q. DID THE COMPANY USE THE NET PRESENT VALUE COST METHOD FOR ITS EXPECTED COSTS OF REMOVAL IN THE CURRENT DEPRECIATION STUDY?

A. No. It would be very expensive to conduct a removal cost estimation study for transmission, distribution, and general assets. Such studies would need to have every asset reviewed to determine expected costs to remove today, the future value of those many individual cost estimates in the year those costs are expected to be spent, and then calculate the present value of those cost streams. The use of the net present value method is further made difficult because it requires the use of a forecasted inflation rate and a forecasted earnings rate over the life of the asset.

In contrast, we use the net present value method for the recovery of the final removal of our nuclear units due to the fact that the future expected costs for removal are sizeable and the cost of obtaining the estimate is justified. For production assets other than nuclear, the Company had a removal cost estimate done and again the expected costs were large enough to justify the cost of the study.

Because of the difficulties in using the net present value methodology for transmission, distribution, and general, the Company instead proposed the method that uses an extensive history of removal costs incurred relative to the assets retired to trend the removal rate along with an operational review of trended results to assure the chosen rate was appropriate.

IV. ASSET RETIREMENT OBLIGATIONS

Q. REGARDING DEPRECIATION METHODOLOGIES, THE SETTLEMENT PROVIDES THAT: "IN ALL OTHER RESPECTS, THE PARTIES RECOMMEND THAT THE COMMISSION APPROVE THE METHODOLOGIES USED BY THE COMPANY IN THIS

PROCEEDING." WHAT IS YOUR UNDERSTANDING OF THE MEANING OF THIS PROVISION?

A. Commission approval of this Settlement provision means, among other things, that continued recovery of removal costs for non-legal AROs is approved.

Q. WHAT IS MR. MAJOROS' REASON FOR SEEKING TO LIMIT REMOVAL COSTS TO THOSE INCURRED FOR LEGAL AROS?

A. Mr. Majoros appears to assume the legal AROs reported by the Company as required under Generally Accepted Accounting Principles (GAAP) represent the Company's only required removal expectations. This is not the case. Allowing recovery of costs for only legal AROs would fall short of actual operating expectations and thus would cause intergenerational inequity.

Q. DOES THE METHOD RECOMMENDED BY MR. MAJOROS MEET WITH FUTURE NET SALVAGE EXPECTATIONS?

A. No. Legal AROs are a subset of the non-legal AROs included in accumulated depreciation for removal costs. The non-legal ARO regulatory liability tracks the amount collected from customers for all removal costs. The intent of incorporating a removal cost estimate into the depreciation rate is to recover what the Company expects to spend upon removal of our assets. The Company does not want to recover more than it expects to need for removal, or less than needed. Too much or too little will cause refunding or recovery of these costs to occur after the asset no longer benefits customers. Thus, not recovering based on actual operating expectations would provide for intergenerational inequity. Therefore, the discussion of what should be included in the depreciation expense for net salvage (expected gross salvage less expected removal cost) should center around expectations of future costs.

Q. PLEASE EXPLAIN THE PURPOSE OF THE FINANCIAL REPORTING REQUIREMENT FOR LEGAL AROS.

A. The Financial Accounting Standards Board (FASB) defines a minimal financial reporting need for those removal activities that are defined by statute, law, rule, or contract (legal AROs). Companies are not required to include in its financial report removal costs that are necessary as part of normal business (non-legal AROs). For example, asbestos removal in a building is legally required and is required to be financially reported; however the removal of the rest of the structure is driven by business necessity rather than by legal requirements and, therefore, the cost of removing the rest of the structure is not required to be reported. The requirement to report on legal AROs is not a pronouncement that non-legal ARO costs do not exist or that a company could avoid them.

Continuing with the example, the asbestos in the building is in the floor tiles, the insulation, and in the caulking around the window panes. Using Mr. Majoros assumption that the only removal the Company is required to incur is what is reported as legal AROs, the Company would remove the asbestos and leave the rest of the building as is. Very few assets can actually be retired in place. All other assets have retirement and removal costs that should be recovered over the useful lives of the assets.

Q. WHAT SPECIFICALLY DOES THE COMPANY INCLUDE IN ITS LEGAL ARO REPORTING?

A. Annually, the Company does an extensive review of the FASB defined legal AROs for proper financial reporting. The following table lists the legal AROs that the Company has reported on for NSP-Minnesota:

Production
Asbestos
Wells
Ash ponds and landfills (including evaporation ponds)
Underground and aboveground storage tanks
Mercury in old control panels
Lead paint
Coal yard at certain facilities on rivers
Transmission and Distribution
Asbestos
Pole top or pad mounted transformers with PCB oil (expected to be less than 5% of equipment)
Substation transformers and capacitors with PCB oil and the carcass that held the oil (expected to be a very small percentage of equipment)
Underground and aboveground storage tanks
Meters with lithium batteries
Paper-insulated, lead-covered underground cable (mostly in the State of Minnesota)
General Plant
Asbestos
Lead paint
Lithium batteries in equipment

There are many expected removal activities and components not covered by the above list, including buildings, transmission lines and poles, distribution lines and pole. These are examples of a few major categories of assets we cannot retire in place.

Q. WHAT WOULD BE THE HARM OF LIMITING NET SALVAGE TO THE LEGAL AROS LISTED ABOVE?

A. The Company would not be allowed to recover the reasonable and appropriate removal costs for its assets. We do not believe that the legal AROs define the Commissions expectations of the Company's responsibilities in this regard, nor do they define the business expectations for dealing with retired assets. As an example, referring to the transmission legal AROs listed above and assuming those listed removal activities represented the limit on removal expectations, the Company would not be expected to remove any pole, tower, or conductor if it needed to replace the equipment because it had failed. Clearly, expectations for removal and the Company's operating practices include more than just the legal ARO removal. Total removal estimates are based on an analysis of what we expect to spend on removing the old equipment. Thus, the old equipment is removed from the field and properly disposed of because it is a prudent and necessary business practice, and thus the costs are recoverable.

Q. WHAT ABOUT MR. MAJOROS' CLAIM THAT THE PU-07-776 SETTLEMENT WAS VIOLATED BECAUSE THERE WAS NOT A LISTING OF THE NON-LEGAL AROS ON FERC FORM 1 AS A REGULATORY LIABILITY?

A. Mr. Majoros made a similar financial reporting request in Case PU-07-776. The Settlement did not incorporate a financial reporting requirement. The Settlement reflects the fact that there is not a separate financial reporting requirement for non-legal AROs. The SEC and FERC only require financial reporting for legal AROs. In recognition of the limited financial reporting requirements the Settlement required that "rate recovery – past, present, and future – for the removal and retirement of Company utility property will be…recognized as a regulatory liability." The Company recognizes its accumulated depreciation as a regulatory liability in GAAP accounting and all money received for removal and retirement is included in and reported as accumulated depreciation, which, in turn, reduces rate base.

Q. COULD THE COMPANY REPORT THE AMOUNTS RECOVERED FOR NON-LEGAL AROS AS A REGULATORY LIABILITY IN FERC FORM 1 AS REQUESTED BY MR. MAJOROS?

A. Not on the standard FERC Form 1 pages, as FERC controls the specific content of FERC Form 1. However, we could provide the information on a separate footnote page to the FERC Form 1. This approach was previously considered by the Commission and parties to the 2007 Settlement. In that case it was determined that including such information in FERC filings was not necessary. While this reporting requirement would not change any of our obligations related to these funds, if the Commission would like us to provide this information as a footnote to future FERC Form 1 filings, we will do so.

V. OTHER DEPRECIATION ISSUES

Q. ARE THERE OTHER DEPRECIATION ISSUES YOU WISH TO ADDRESS IN YOUR TESTIMONY?

A. There are three other issues raised by Mr. Majoros that I wish to address:

- the estimate of negative 100% net salvage for the distribution FERC Account 364, Distribution Poles, Towers & Fixtures.
- how the first alternative recommendation Mr. Majoros makes on page 3, lines 5-6, of his Direct Testimony dealing with the theoretical reserve surplus was accomplished by the Company in its depreciation proposal.
- the contention that the Commission was not made aware of the MPUC dockets on nuclear decommissioning.

Q. DID THE COMPANY USE AN INFLATED COST METHODOLOGY, AS MR. MAJOROS ASSUMES, PAGE 15, IN DETERMINING A 100% NET SALVAGE FOR FERC ACCOUNT 364?

A. No. As I explained earlier, the Company is using a historical trended cost, not a future inflated cost methodology. The Company proposes a negative 100% net salvage for FERC Account 364, Distribution Poles, Towers & Fixtures based on historical information. The most recent 5 and 10 year moving averages show negative 233.77 percent and negative 151.15 percent net salvage, respectively. The actual retirement data for 2007-2011 indicates net salvage percentages significantly higher than in previous years approaching negative 500%. As such, the Company is proposing a negative 100% net salvage to represent the trending increase in removal costs while not providing too much weight to the outliers in years 2007-2011.

Q. PLEASE DISCUSS USING THE DIFFERENCE BETWEEN ACTUAL AND THEORETICAL RESERVES FOR TRANSMISSION, DISTRIBUTION, AND GENERAL ASSETS TO LOWER DEPRECIATION EXPENSE.

A. The Company proposes using the existing depreciation reserve surplus for Transmission, Distribution and General assets to lower depreciation expense by $5.094 million on a total Company basis. This reduction in expense will continue over the remaining lives of the assets. Mr. Majoros proposes "retention of the whole-life procedure with a separate amortization of any significant reserve imbalances." Although he states this as an alternative from what the Company proposed, it actually is what the Company proposes. With the current transmission, distribution, and general plant depreciation study, whole-life depreciation is first determined. Using the proposed whole-life, survivor curve, and net salvage rate along with vintaged asset values, a theoretical reserve is calculated. This theoretical reserve is compared to the actual reserve. A theoretical reserve greater than the actual reserve is a surplus, and the converse is a shortfall. The Company proposed that this theoretical to actual reserve difference be spread over the remaining life of the asset group.

Q. PLEASE RESPOND TO THE ASSERTION THAT THE COMPANY SHOULD HAVE INVITED THE COMMISSION TO PARTICIPATE IN THE TRIENNIAL DOCKET BEFORE THE MINNESOTA COMMISSION.

A. With respect to our nuclear decommissioning proceedings in Minnesota, the process agreed to by parties in Case No. PU-07-776 is as follows:

> For informational purposes, the Company will submit to the Commission the various depreciation studies and related documents that are periodically filed with the Minnesota Public Utilities Commission. Such filings include: Annual Review of Remaining Lives, Average Service Life and Vintage Group Filing (every five years), *Triennial Review of Nuclear Decommissioning*. (Emphasis added.)

The Company has fully complied with this process. The letter sent to Commission Staff regarding the last triennial filing for 2011 (excluding the filing documents that also were sent) are provided in Exhibit___(LHP-2) Schedule 3.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. I have demonstrated that the Company is in compliance with the Commission approved Settlement in Case No. PU-10-776 because we:

- reflected North Dakota specific depreciation rates in our annual earnings reports;
- filed the required notice concerning a North Dakota distribution study in our last rate case, and in this current rate case filed a North Dakota specific depreciation study;
- use funds recovered for retirement and removal solely for that purpose; have created a regulatory asset for the accumulated depreciation related to retirement and removal, and the accumulated depreciation, including amounts recovered for retirement and removal, reduces rate base;
- used a historical cost trend methodology, not a future cost methodology, to determine the cost of removal; and
- provided the Commission with a copy of our Triennial Review filing with the MPUC.

I further explained that the Company incurs removal costs for most of its assets and is entitled, under the Settlement and as a cost of providing service, to recover those costs. Mr. Majoros' proposal to recover only legal ARO costs is inconsistent with the Settlement provision approving all of the Company other methodologies.

I also explain our proposal to use the existing surplus accumulated reserve margin for transmission, distribution, and general assets to lower rates over the remaining lives of those assets.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	)	Case No. PU-12-813

AFFIDAVIT OF
Lisa H. Perkett

I, the undersigned, being duly sworn, depose and say that the foregoing is the Rebuttal Testimony of the undersigned, and that such Rebuttal Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Lisa H. Perkett

Lisa H. Perkett

Subscribed and sworn to before me, this 8th day of August, 2013.

Virginia J. Sailor

Notary Public
My Commission Expires: 1/31/16

VIRGINIA J SAILOR
NOTARY PUBLIC - MINNESOTA
MY COMMISSION EXPIRES 1/31/16

PROPOSED DEPRECIATION RATES

	Proposed Depr Rate %
Electric Transmission	
Lines	1.9130
Lines - Prod	1.9761
Plant Leased to Other	2.1298
Substations	1.7464
Substations - Prod	1.6878
Electric Distribution	
Lines	2.8237
Other	4.5665
Substations	2.2626
Street Lighting	4.7747
Electric General	
Buildings	1.9688
Communication Equipment	10.7571
Communication Equipment - EMS	6.4851
Communication Equipment-PBX-AMR	6.7081
Furniture & Equipment	4.8295
Network Equipment	23.2815
Tools & Other Equipment	6.5883
Transportation Equipment	7.5181
Electric Software	
Software	18.9911
Common General	
Building	2.2296
Building-Leased	10.7324
Communication Equipment	11.9005
Communication Equipment-PBX	12.0571
Furniture & Equipment	5.3182
Network Equipment	25.9653
Tools & Other Equipment	6.9361
Transportation Equipment	8.0559
Common Software	
Software	19.9616

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October 15, 2010

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: DISTRIBUTION FACILITIES DEPRECIABLE LIVES

Dear Mr. Nitschke:

In Xcel Energy's previous rate case (PU-07-776), the approved Settlement Agreement contained a provision requiring the Company to indicate to the Commission, in advance of its next electric rate case, its intentions regarding whether to propose North Dakota-specific depreciable lives for its distribution facilities in the state. With this letter, I wish to inform the Commission that we do not intend to propose any changes to the currently approved and North Dakota-specific depreciable lives for distribution facilities in our upcoming rate filing.

Please contact me if you have any questions or comments.

Sincerely,

David H Sederquist

DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION/FINANCE

cc: Michael Diller

414 Nicollet Mall
Minneapolis, Minnesota 55401

— **VIA ELECTRONIC FILING**—

November 30, 2011

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION
2012-2014 TRIENNIAL NUCLEAR PLANT DECOMMISSIONING ACCRUAL
DOCKET NO. E002/M-11-939

Dear Dr. Haar:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), submits to the Minnesota Public Utilities Commission (the "Commission") a Petition for approval of our *2012-2014 Triennial Nuclear Decommissioning Accrual* and supporting materials. This filing is submitted in compliance with the Commission's Order in Docket No. E002/D-86-604 to review nuclear decommissioning financial parameters, funding methodology, and the cost estimate every three years, and in accordance with Minn. Rules 7825.0500 through 7825.0800. In addition, we present multiple accrual scenarios as required by Minn. Stat. § 216B.2445, enacted during the 2011 Minnesota legislative session, and we provide options to address the various accrual scenarios. We propose a January 1, 2013 effective date for the new decommissioning accrual.

Late in the preparation and review of this filing, we discovered that the accrual excluded approximately $1 million per year of property taxes. We are currently rerunning the analysis and will submit the updated reports by December 30, 2011. We apologize for the inconvenience. However, the updated information will provide the Commission the basis to make an informed decision after a full and thorough vetting of the assumptions and consideration of all possible options.

Pursuant to Minn. Stat. § 216.17, subd.3, we have electronically filed this Petition and supporting materials to the Commission and the Minnesota Department of Commerce, Division of Energy Resources ("DER"). Two copies have also been provided to the Office of the Attorney General – Residential Utilities Division. Copies have also been provided to the nuclear plant host cities and counties, the Cities of Red Wing and Monticello, legislators representing the host cities, and the Prairie Island Indian Community. In addition, a one page summary of the filing has been provided to persons on the official service list for this filing and our 2009 Triennial Decommissioning Accrual filing (Docket No. E002/M-08-1201) and a number of related nuclear dockets identified in our Certificate of Service. The one-page summary provided also contains directions on how to access an electronic copy on Xcel Energy's website.

Please contact Al Krug, Managing Director, Regulatory Affairs, at 612-330-6270, or allen.krug@xcelenergy.com if there are any questions regarding this filing.

Sincerely,

/s/

JEFFREY S. SAVAGE
VICE PRESIDENT AND CONTROLLER

cc: Service Lists
Interested Parties List

State of Minnesota
Before the
Minnesota Public Utilities Commission

Ellen Anderson	Chair
David Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR APPROVAL OF THE 2012-2014 TRIENNIAL NUCLEAR DECOMMISSIONING ACCRUAL

DOCKET NO. E002/M-11-939

PETITION

OVERVIEW

Pursuant to Minn. Stat. § 216B.11 and § 216B.2445 and Minn. R. 7825.0500 through 7825.0800, and prior Commission orders, Northern States Power Company ("Xcel Energy" or the "Company"), a Minnesota corporation, submits our Petition for approval of the 2012-2014 Nuclear Decommissioning Accrual. The Company requests the Minnesota Public Utilities Commission (the "Commission"):

- Approve our decommissioning study and assumptions as reasonably approximating the amount of funds necessary to support decommissioning at the end of our nuclear facilities' operating lives;
- Approve an annual accrual of approximately $13.6 million for decommissioning and an increase of $171,091 for end-of-life nuclear fuel starting January 1, 2013; and
- Apply a portion of future settlement payments received from the United States Department of Energy ("DOE") to the accrual, eliminating the need to begin charging customers to fund the deficit, and crediting the remainder of the Settlement funds to customers.

The increase in proposed accruals in this filing from zero to $13.6 million is primarily the result of three factors. The first factor is an increase in the estimated costs for decommissioning activities, from $2.4 billion to $2.6 billion. The second factor is an increase in the escalation factor used to inflate the costs into future dollars, from 2.89% to 3.63% during radiological decommissioning activities. The third, and most significant change, is a decrease in the assumed earnings rate used to determine future growth of the invested funds, from 6.3% to 4.41% - 5.54% (depending on unit and scenario).

Consistent with Minn. Stat. § 216B.2445, the Company provides scenarios assuming used fuel will be stored in the state for 60 years, 100 years, and 200 years following cessation of operations at the plant.[1] In addition, the Blue Ribbon Commission on America's Nuclear Future ("BRC") is scheduled to issue its report by the end of January 2012. The BRC's draft report issued mid-year 2011 recommends prompt development of centralized interim storage and we do not anticipate that recommendation will change. Consistent with that recommendation, we have provided a preliminary analysis assuming used fuel will be stored in the state for 36 years. The Company currently estimates that an accrual of approximately $13.6 million beginning in 2013 will be necessary to adequately support the decommissioning fund based on the preliminary 36-year scenario.

The overall goal of the decommissioning accrual schedule is designed to ensure intergenerational equity among customers to the extent possible, such that the customers who benefit from nuclear power pay the costs associated with that power at the time it is generated. While the basis of the decision framework remains sound, we will ensure that the accruals are as accurate as possible for Commission decision-making and include analysis for those scenarios reasonably reflective of current circumstances and those that the legislature has specifically directed the Company and Commission to evaluate.

In this Petition, we outline:

- The calculation of the decommissioning accrual, including an explanation of the primary factors that have changed since the last filing;
- The status of the fund balances to date and the influence this has on the overall accrual; and
- Funding alternatives for the decommissioning accrual.

In addition, the financial analysis shows a continued need for the Escrow and we have separately and concurrently filed for a change to the Custody and Escrow Agreement ("Escrow Agreement") language to allow a more robust investment structure that could increase the earnings potential of these funds through the

[1] As explained in the cover letter to this Petition, late in the preparation of this filing, the Company identified a cost factor was inaccurately stated in its analysis. We estimate this could impact the accrual by approximately $1 million per year. We are currently re-running the analysis and will submit an update by the end of December.

operating period. The assumptions included in the decommissioning study already reflect the proposed change in investment strategy for the Escrow.

I. Summary of Filing

A one-paragraph summary of the filing accompanies this Petition pursuant to Minn. R. 7829.1300, subp. 1.

II. Service on Other Parties

Pursuant to Minn. Stat. § 216.17, subd.3, we have electronically filed this Petition and supporting materials to the Commission and the Minnesota Department of Commerce, Division of Energy Resources ("DER"). Two copies have also been provided to the Office of the Attorney General – Residential Utilities Division. Copies have also been provided to the nuclear plant host cities and counties, the Cities of Red Wing and Monticello, legislators representing the host cities, and the Prairie Island Indian Community. In addition, a one-page summary of the filing has been provided to persons on the official service list for this filing and our 2009 Triennial Decommissioning Accrual filing (Docket No. E002/M-08-1201), Xcel Energy's Miscellaneous Electric Service List and a number of related nuclear dockets as identified in our Certificate of Service and listed below:

- Docket No. E002/CN-05-123 Monticello ISFSI[2]/Life Extension
- Docket No. E002/CN-08-185 Monticello Extended Power Uprate
- Docket No. E002/CN-08-509 Prairie Island Extended Power Uprate
- Docket No. E002/CN-08-510 Prairie Island ISFSI/Life Extension
- Docket No. E002/CN-09-36 Annual Nuclear Waste Management Report
- Docket No. E002/RP-10-825 Resource Plan
- Docket No. E002/GR-10-971 Electric Rate Case
- Docket No. E002/M-08-1201 2009 Nuclear Decommissioning Accrual

The summary provided also contains directions on how to access an electronic copy of the filing on the Xcel Energy website.

III. General Filing Information

Pursuant to Minn. R. 7825.3200, 7825.3500, and 7829.1300, subp. 3. Xcel Energy provides the following required information:

[2] Independent Spent Fuel Storage Installation.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Kari L. Valley
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C. Date of Filing and Date Proposed Accrual Will Take Effect

This Petition is being filed November 30, 2011. Xcel Energy requests that upon Commission approval the increase to the accrual become effective beginning January 1, 2013.

D. Statute Controlling Schedule for Processing the Filing

Under Minn. R. 7829.0100, subp. 11, this request for approval of decommissioning accrual is a "miscellaneous" filing because no determination of the Xcel Energy general revenue requirements is necessary. There is no specific statute that prescribes the amount of time the Commission has to rule on this Petition.

E. Utility Employee Responsible for the Filing

Allen D. Krug
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IV. Decommissioning Accrual

A. Introduction

The primary objective of a decommissioning docket is to arrive at a reasonable estimate of what it will cost to decontaminate and remove the nuclear facilities at the end of the operating lives of the nuclear plants. Once an estimate is established, the Commission determines the amount of expense to accrue annually to accumulate a fund sufficient to pay the decommissioning costs when incurred.

The Commission historically has been concerned that rates charged for current production reflect the expected cost to decontaminate and decommission the facilities, spread over the remaining lives of the plants. The Commission approves the decommissioning study and an associated accrual when it finds that the analysis is a reasonable approximation of the expected decommissioning costs and in the public interest.[3]

Similar to previous decommissioning filings, our Petition presents a number of issues for the Commission to consider and the revision of any assumption takes on particular importance in this filing. Small changes in assumptions have significant impacts on current and future accruals due to the relatively short period of time assumed to recover the decommissioning costs.[4] The assumptions included in this analysis result in a reasonable estimate of future decommissioning costs and tie the costs of nuclear generation, including decommissioning costs, to the customers that currently benefit from this resource. Accordingly, the Commission should find these assumptions reasonable and approve the proposed study and resulting accrual.

B. Assumptions and Results

Consistent with previous filings, in this filing, the Company examines the impact of assumptions in the engineering cost estimate, costs associated with spent fuel storage following plant shutdown, escalation, inflation and earnings rates, fund investment structure, and recovery period.

In 2011, the Minnesota legislature directed the Company to include in its decommissioning fund filing analyses assuming used nuclear fuel will be stored in the state for 60 years, 100 years, and 200 years following the cessation of

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3 *See In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the 2005 Review of Nuclear Plant Decommissioning,* Docket No. E002/M-05-1648, ORDER SETTING END-OF-LIFE DATES AND OTHER GUIDELINES FOR NUCLEAR DECOMMISSIONING ACCRUAL at 6 (March 23, 2006).

4 Approximately 20 years of additional plant operations compared to the 200 year scenario for potential on-site storage required by Minn. Stat. § 216B.2445.

operations. The Company has computed the corresponding decommissioning accruals for 2013 for the 60 year, 100-year, and 200-year cost estimate scenarios. The 200-year scenario was performed with two variations; the first 200-year scenario assumes the dry casks would be viable for the entire period and the second 200-year scenario assumes all dry casks are replaced at the 100 year mark.

In addition, the Company has prepared a preliminary estimate of the accrual for a 36-year scenario.[5] The 36-year scenario represents the same decommissioning timeline as presented in our last decommissioning filing with updated costs. This timeframe is consistent with the timeline that could be realized considering implementation of the BRC's recommendation for centralized interim storage.

The Company has presented five scenarios in total. The decommissioning scenarios depicted in Table 1 below result in the following 2013 accrual for the Minnesota jurisdiction:

Table 1 – Summary of 2013 Accruals

Decommissioning Period	2013 Accrual
36 years	$13,563,239
60 years	$13,354,861
100 years	$15,476,189
200 years (1)	$16,745,864
200 years (2)	$19,143,066

The accrual scenarios contained in this petition have been modified to reflect modifications of the current Escrow Agreement to allow for a more aggressive asset mix than the currently allowed escrow holdings of cash equivalent investments. The increased flexibility provided by the changes will allow for more efficient tax planning and increase the expected earnings rate of the escrow account. Since the accrual scenarios in this petition already reflect a change in investment strategy, to the extent the Escrow Agreement is not modified, the accruals presented would likely need to increase to reflect continuation of the more conservative investment approach. We have submitted a petition for approval of those modifications concurrent with this filing. We recommend the commission act on the escrow investment strategy issue early in 2012 as it may take time to modify existing account structures and implement the new allocations. Additionally, in order to be as consistent as possible with the accrual calculation

5 We will provide a full decommissioning fund analysis for the 36-year scenario by February 1, 2012. The February 1 analysis is in addition to the property tax update to be filed by December 30, 2011.

analysis, changes to the investment structure of the escrow account should be made as soon as possible. A delay in approval of the modified Escrow Agreement could result in higher accruals than currently reflected in this petition.

C. Primary Factors Changed Since 2008 Petition

The decommissioning analysis is comprised of mainly three discrete steps. The first is to determine a decommissioning cost estimate for a chosen scenario that equates to a period of time it is anticipated the federal government will begin accepting used nuclear fuel and when the last shipment of used nuclear fuel leaves our plants.[6] The second is to determine the earnings estimate based on the investment mix over the period of time. This includes an analysis of the expected returns on various asset classes and changing investment strategies based on when liquidity would be needed to cover decommissioning costs. The third step is to determine an annuity necessary to fully fund the costs of decommissioning each site based on the earnings estimates developed for that scenario.

This Petition examines the impact of assumption changes in the five primary areas that contribute significant variability to the amount needed for decommissioning at the expiration of operating licenses and are summarized as follows:

- *Changes to the engineering cost estimates.*

  Revised engineering cost estimates, using multiple fuel storage scenarios to comply with new statutory requirements;

- *Changes in assumptions about escalation/inflation of costs over time.*

  Multiple escalation/inflation rates: one for the operating and plant decommissioning period and one for the ISFSI and site restoration period;

- *Revisions to the expected earnings rate for the Qualified Trust and Escrow combined.*

  Multiple earnings rates, one set for each cost estimate scenario: one for the operating period and one for post shutdown period;

- *Investment structure throughout operations and decommissioning period.*

  Use of the August 31, 2011 actual market value fund balances instead of the determination of a theoretical balance as used in prior filings: recommendation to rebalance the Escrow account;

- *Expiration dates of the operating licenses.*

[6] It is assumed that the site is fully dismantled, radiologically decontaminated, and restored.

Extension of Prairie Island's operating period to 2033/2034 to reflect the approval of the operating license extension. The recovery period for all facilities is now based on a 60-year operating life.

Detailed discussion of these changes is provided below.

1. *Cost Estimate*

One issue that influences the pattern of decommissioning expenditures is the procedures in place for the handling of spent fuel; mainly the period spent fuel remains in the pool and is stored on site. As with all decommissioning cost estimates, the dismantlement and removal of contaminated structures cannot be completed until all spent fuel has been removed from the reactors and storage pools and placed in dry storage containers in a storage facility. Final release of the site from all licenses comes when all the fuel is removed from the on-site storage facility and the storage facility has been removed. The difference in the 36-year, 60-year, 100-year, and the two 200-year scenarios is around the storage facility operational period. The radiological decommissioning of the nuclear plant is constant throughout all scenarios.

In the Company's last nuclear decommissioning filing it was assumed that a federal off-site storage or disposal facility would be available in 2025 allowing spent fuel to be removed from Xcel Energy's Minnesota nuclear plant sites by 2053 at Prairie Island and 2066 at Monticello. In such a scenario, known as Prompt Removal and Dismantlement or DECON[7], it is assumed in the cost estimate that all spent fuel used would be removed from the storage pools after approximately 12 years at Monticello and 15 years at Prairie Island to meet cool down requirements and placed in dry storage. It was assumed that the federal government would begin removing fuel from our sites while the plants are still operating and that the overall fuel removal schedule only added approximately 20 years to the overall decommissioning period at Prairie Island and 36 years at Monticello.[8]

In the current filing, it is assumed that spent fuel will be moved off-site such that all fuel will be removed from Minnesota within the required 60-year, 100-year, or

[7] DECON is defined by the NRC as, "[a] method of decommissioning in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a low-level radioactive waste landfill or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."

[8] Since the last decommissioning filing, the Department of Energy has terminated its efforts to open the planned Yucca Mountain spent fuel storage facility, which in the 2008 filing was the presumed off-site destination for spent fuel. The termination of the Yucca Mountain project is currently under legal challenge. In parallel with DOE's efforts to terminate the Yucca Mountain project the Secretary of Energy has established the Blue Ribbon Commission on America's Nuclear Future to evaluate alternatives to Yucca Mountain. A status of the Blue Ribbon Commission is provided below in Section C.1.a, and includes Xcel Energy's assessment of the period that spent fuel could potentially remain on-site. http://www.brc.gov/sites/default/files/documents/brc_draft_report_29jul2011_0.pdf

200-year timeframe specified by Minn. Stat. § 216B.2445. Two 200-year cost estimates have been provided showing a scenario where the fuel casks last the entire period and another where the fuel casks are replaced at 100 years. In addition, we have evaluated a 36-year scenario, assuming a centralized interim storage facility will begin operation in 2025, allowing shipments from the Prairie Island and Monticello sites to begin in 2027 with all spent fuel being removed from Minnesota by 2066. Based on the current status of the BRC's support for centralized interim storage, the 36-year scenario may represent a realistic length of time for all spent fuel to be shipped off-site to a federal facility following the shutdown of Monticello and Prairie Island, assuming that the federal facility will be capable of receiving 3,000 metric-tons heavy metal each year from all nuclear power plants nationwide.[9]

The determination of the nominal costs for total decommissioning of each unit relies upon the prompt removal of the plant facilities shortly after shut down and the estimated spent nuclear fuel acceptance schedule for transferring the spent fuel over to the federal government or another offsite facility. Company representatives extrapolate these fuel-shipping schedules from basic information provided by the federal government.

In developing the strategy for spent fuel shipping for the 60-year, 100-year, and 200-year scenarios, a key assumption made is that for cost saving purposes, fuel would be shipped from one site first (Prairie Island), followed by shipping from the second site (Monticello). Allocations of space for shipping to a federal facility are provided on a company-wide basis and Xcel Energy has the discretion to ship spent fuel from either site first or both sites at the same time. If spent fuel was shipped from both sites over the period of shipping, both ISFSIs would have to operate for the entire time period following shutdown, i.e. 60 years, 100 years, or 200 years. By completing shipping from one site first, followed by shipping from the second site, overall costs would be lowered because the costs of operating and securing the first site's ISFSI are eliminated approximately 13 years earlier. This is the case for all but the 36-year scenario. Due to a need to cool the spent fuel following discharge from the reactor for a minimum of 30 years prior to shipping, the 36-year scenario assumes shipping from both sites simultaneously, resulting in the Prairie Island ISFSI operating until 2064 (30 years after plant shutdown) and the Monticello ISFSI operating until 2066 (36 years after plant shutdown). Table 2 below depicts the years that spent fuel shipping will begin and finish for the 36-year scenario and the required 60-year, 100-year, and 200-year scenarios.

[9] For more information pertaining to the DOE's progress toward its removal of spent nuclear fuel from Minnesota's nuclear plants, see the Company's most recent Annual Nuclear Waste Management Report at Docket No. E002/CN-09-36 filed on August 10, 2011.

Table 2 – Spent Fuel Shipping Schedules

Plant	Year of Plant Shutdown	Year Shipping Begins	Year Shipping Finishes
36-Year Scenario			
Prairie Island	2034	2027	2064
Monticello	2030	2053	2066
60-Year Scenario			
Prairie Island	2034	2051	2077
Monticello	2030	2077	2090
100-Year Scenario			
Prairie Island	2034	2091	2117
Monticello	2030	2117	2130
200-Year Scenario			
Prairie Island	2034	2191	2217
Monticello	2030	2217	2230

Our consultant, TLG Services, Inc. ("TLG"), performed site specific cost estimates for the 60-year and two 200-year scenarios. Schedule A (A.1 – A.10) shows both TLG's schedule of annual expenditures for the 60-year and two 200-year cost scenarios along with 36 year and 100-year cost scenarios which are versions of the TLG schedules of annual expenditures modified by the Company to the proper decommissioning length. Schedule B shows the required NRC minimum funding calculation applicable to Xcel Energy's facilities. The Company converted the 200-year scenario into a 100-year scenario by shortening the dry cask operating period and modifying costs after radiological decommissioning as appropriate. The 100-year cost scenario was created to meet the enhanced reporting requirements mandated in new state statute.

Based on the preliminary findings from the BRC, we determined that shorter cost estimate was a viable option. The Company converted the 60-year cost estimate scenario into a 36-year scenario to develop the preliminary estimate in this filing. We have directed TLG to complete a detailed cost estimate to support this time period.

All of the timeframes analyzed demonstrate a need for additional accruals in the near term. The results provide further support that the proposed accrual is sound. A more complete comparison between the cost estimates from the previous filing to this one is shown in Schedule A. For further reference, included along with the study in support of these cost estimates are the more detailed summary reports for Monticello and Prairie Island respectively, as performed by TLG for the 60-year and two 200-year cost estimates.

a. Period that Spent Fuel Could Potentially Remain On-Site

The Company believes that the period of time that spent fuel could realistically remain on-site in Minnesota is driven by two current efforts. The first is the activities of the BRC on America's Nuclear Future and the second is the NRC's Nuclear Waste Confidence Decision.[10]

The BRC has recommended in its draft report issued in June 2011 that a deep-geologic repository should be pursued expeditiously and in parallel with the repository's development, centralized interim storage facilities be established that allow the federal government to begin movement of spent fuel off of existing nuclear power plant sites, thereby fulfilling the federal government contractual obligations. The BRC's final report and recommendations are due to be issued in January 2012. If the recommendation to establish centralized interim storage remains in the final report it is feasible that such a facility could reasonably be sited, constructed and begin receiving fuel by 2025. The projected 2025 timeframe would allow three years for Congress to act on the BRC's recommendations and to enact any required legislative changes and ten years for the facility to be sited, licensed and constructed. Transportation planning to the centralized interim facility would be accomplished in parallel with the siting and construction activities. A centralized interim storage facility would utilize existing dry cask storage and transportation technologies that are already licensed and operating at commercial nuclear power plants. The year 2025 is the earliest that spent fuel might be moved from Minnesota nuclear power plants and this early date would be consistent with the timeframe for movement of spent fuel in the 2008 decommissioning filing and the 36-year scenario.

The backend of the period that spent fuel could potentially remain on site at this time is established by the current Nuclear Waste Confidence Decision put in place by the NRC in 2010. That decision established that spent fuel could be safely stored on site for 60 years following the cessation of reactor operations without significant environmental impacts. In order to allow spent fuel storage for longer than 60 years after the cessation of reactor operations the NRC will have to provide an updated basis for changing that time period. The NRC recently held public meetings to discuss their plans for research to develop a technical basis for extending the 60 years to a longer period of time up to 300 years. However, until

[10] A copy of the BRC's draft report on America's Nuclear Future dated July 29, 2011 can be found at the following web location: http://brc.gov/sites/default/files/documents/brc_draft_report_29jul2011_0.pdf. A copy of the final update of the NRC's Waste Confidence Decision dated September 15, 2010 can be found at the following web location: http://www.nrc.gov/reading-rm/doc-collections/commission/cvr/2009/2009-0090vtr.pdf

an adequate basis is established to change the 60-year period there is no statutory basis to assume on-site spent fuel storage can remain for a period longer than 60 years.

b. Assessment of Future Costs on State and Local Communities

Minn. Stat. § 216B.2445, subd. 1(a) requires the Commission to evaluate the costs, if any, arising from storage of used nuclear fuel that may be incurred by the state of Minnesota, and any tribal community, county, city, or township where used nuclear fuel is located following the cessation of operations at a nuclear plant when considering approval of a plan for the accrual of funds for decommissioning nuclear generating facilities.

We look forward to input from our host communities on this topic. At this time, the Company has not identified any costs that the storage of used nuclear fuel will impose on the State of Minnesota, and any tribal community, county, city or township following the cessation of operations at either Prairie Island or Monticello. Costs related to plant operations incurred by state and local communities at present are for offsite radiological emergency response services. Current NRC guidance indicates that once the reactors cease operations, offsite emergency planning for ISFSIs is not required given the extremely low probability of a radiological incident. [11]

While these radiological emergency response services may no longer be necessary once the reactors cease operations, we recognize that our neighboring communities and related government agencies are cooperative partners in the planning of emergency preparedness activities in a variety of scenarios. We will continue to work with our neighboring communities to ensure that all emergency response needs of the plants are met. We anticipate the parties may have varying views of the services that will be necessary and cost of those services and encourage them to raise those issues during this proceeding to ensure an appropriate level of services is identified and funded.

c. Property Taxes Included in Cost Estimates

In the 1970's, personal property taxes were phased out for all industries except the utility industry. The utility industry continues to pay property taxes on both real and personal property.

[11] *Emergency Planning Licensing Requirements for Independent Spent Fuel Storage Facilities (ISFSI) and Monitored Retrievable Storage Facilities (MRS),* 60 Fed. Reg. 32430, 32431 (June 22, 1995) (referencing NUREG-1140, A REGULATORY ANALYSIS ON EMERGENCY PREPAREDNESS FOR FUEL CYCLE AND OTHER RADIOACTIVE MATERIAL LICENSES (1988)).

Taxation of utility property is fundamentally different than taxation of the property owned by any other business. Like other businesses, we pay property taxes on the value of the land we own, the buildings attached thereto, and rights-of-way. This property is all assessed at the local level. Unlike other businesses, however, we are also assessed property taxes on personal property. Specifically, we are required to pay property taxes on Operating Property, which is defined as "any tangible property that is owned or leased, except land, which is directly associated with the generation, transmission, or distribution of electricity [or] natural gas…." Minn. R. 8100.0100, subp. 11.

The Minnesota Department of Revenue ("DOR") first values all of the Company's operating property in Minnesota, as well as its gas and electric operating property that extends into North Dakota and South Dakota. Each type of property is valued as one integrated system, or unit. When the system value for each type (electric or natural gas) is determined, an allocation is then made to reflect how much of the system value is attributable to Minnesota. Allocation is based on a combination of original cost of the property in Minnesota to total system cost, as well as gross revenue in Minnesota to total system revenue.

Deductions are then made to subtract property locally assessed (land and some buildings) and exemptions (e.g., sliding scale exemption for generation efficiency, pollution control, etc.). The resulting value is then apportioned to the various taxing districts based on the original cost of the property located in those districts.

Local taxing districts then combine the market value apportioned to them with the value of the Company's locally assessed property to arrive at our tax base within the taxing district's jurisdiction. Finally, each jurisdiction then applies its own individual property tax rate to our tax base to determine our property tax liability in that jurisdiction.

As we make new investments in personal property throughout our integrated system, the market value upon which property taxes are assessed increases. This increased market value is then apportioned to the local jurisdictions that host our Monticello and Prairie Island plants. In 2010, the Company paid $6.7 million in real and personal property taxes related to Monticello and $10.7 million for Prairie Island. In 2011, the Company paid $8.1 million in property taxes related to Monticello and $10.9 million for Prairie Island. When the operations at these nuclear plants cease, the operating property will be removed from these sites and will no longer be included in the DOR's market valuation. This will result in a reduction in property taxes paid when operations cease, but the property for the ISFSI will continue to be locally assessed. For the decommissioning cost estimates, the land, structures, and the dry cask portion of the operating property taxes were assumed to continue with the structures component lasting until the structures are decommissioned and removed.[12]

2. Escalation/Inflation Rate

Pacific Global Advisors ("PGA"), an investment-consulting firm, provided the forecast analysis for the escalation/inflation rates proposed for this analysis. A more comprehensive narrative of this analysis and accompanying graphs are included in Schedule C. This narrative includes a discussion of the economic and inflation factors, including gross national product growth, labor productivity, and other considerations, utilized in estimating long-term inflation rates. It also includes a discussion of how these factors are incorporated into the PGA model.

The Company is recommending a 3.63% escalation rate for the remaining operational period through the radiological decommissioning period. The operational years for the dry cask storage and the final site restoration the Company recommends a 2.63% rate of escalation. The drop of 1% in the escalation rate during the later periods reflects the fact that there is a small labor force comparatively and thus the influence of labor escalation on the overall rate is reduced. These two rates were factored into the calculation of the future cost of nuclear decommissioning beginning at the point when decommissioning of the main plant is completed and operations of the ISFSI begin. For example, under the 36-year scenario the lower rate of escalation is assumed to begin in 2047 for Monticello and 2051 for Prairie Island. These rates compare to the 2.89% escalation rate in the last study for the entire period. The two-tiered rate structure is centered around the previous rate, with the overall effect being an increase due to escalation

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3. Forecast Earnings Rate

PGA provided the analysis for the forecast earnings rate, which was reviewed internally for reasonableness since there is no single industry standard method for determining long term asset class forecasts. A more comprehensive narrative of this analysis and accompanying graphs are included in Schedule D. This narrative includes a discussion of the analytical method used by PGA to arrive at the assumed earnings rates used in the following analysis. This discussion includes the method of determining investment strategy, investment and economic assumptions, and the expected returns for the various classes of investments which are currently a part of the funds investment strategy.

While there are inherent risks in any forward looking earnings and escalation/inflation forecasts, the longer it takes to complete the decommissioning, the more time the fund has to compound earnings on the amounts contributed.

[12] The Company will include its updated property tax assessment in its December 30 filing.

However, it also subjects the fund accumulation to more risk if the estimated earnings are not realized as expected.

Once again, the Company is recommending a stratification of the earnings rate between the operational period and the decommissioning period. We also are recommending two earnings rates for each facility to better match the earnings rates with the individual cost estimates and to better replicate the separation in the NRC trust funds. Table 3 below shows the expected net after-tax returns that are representative of the analysis detailed in Schedule D.

Table 3: Earnings Rates Forecast

	36-year Earnings Rates	
Nuclear Unit	Operations	Decommissioning
Monticello	5.34%	4.61%
Prairie Island Unit 1	5.50%	4.48%
Prairie Island Unit 2	5.53%	4.41%

	60-year Earnings Rates	
Nuclear Unit	Operations	Decommissioning
Monticello	5.35%	4.82%
Prairie Island Unit 1	5.50%	4.66%
Prairie Island Unit 2	5.53%	4.57%

This compares to the more optimistic rate of 6.30% assumed in the previous filing for both the operations and decommissioning periods of all three units. The decrease in the expected after-tax returns is the result of changes in market and economic conditions since the last filing date and subsequent decrease in asset class return forecasts and expected market growth going forward.

4. *Investment Structure*

Per the Commission's July 20, 2006 Order in Docket E002/M-05-1648, the external fund is made up of two components. The first component is the qualified trust fund ("Qualified Trust"), which has been provided in previous decommissioning filings. The Qualified Trust is a standard decommissioning fund, which cannot be refunded to customers until all decommissioning activities are completed. The Company has established an individual Qualified Trust for each nuclear operating unit to hold the decommissioning funds required by the NRC.

The second component is the Escrow. The Commission approved the use of this Escrow for current decommissioning funding to better balance the need to ensure that adequate resources will be available to pay the costs to decommission the units when those costs come due, with the goal of continuing to ensure that one generation of customers does not pay a disproportionate share of the decommissioning expense. This Escrow provides a sense of flexibility as funds, via Commission order, can be withdrawn from this fund, when its determined they are no longer needed to fund decommissioning activities, and be returned to customers. A refund to customers of the Monticello portion of the Escrow was ordered in the previous nuclear decommissioning triennial filing.[13]

In addition the Escrow accounts are subject to pour-over at the end of operations should there be a shortfall into the Qualified Trust. The Escrow is a single fund with each operating unit tracked separately within this fund. The Escrow does not qualify for current year tax deductions and thus is a form of a non-qualified fund.

a. Rebalancing of Accounts

After a thorough review of the Escrow balances, we are requesting the ability to rebalance the Monticello, Prairie Island Unit 1 and Prairie Island Unit 2 accounts for the Minnesota retail customers. The Prairie Island Unit 1 decommissioning account is slightly more funded based on its remaining operating life of 2033, approximately 89% funded presently, than Monticello and Prairie Island Unit 2 which are 83% funded presently.[14] This result is contrary to expectations that Monticello would be slightly more funded than Prairie Island Unit 1 because it has the shorter remaining life, and Prairie Island Unit 2 would be slightly less funded than Unit 1 due to the remaining life being one year longer.

Depending upon the cost estimate and period chosen, the Company requests the ability to rebalance the Prairie Island fund balances to minimize the current funding needs for Monticello. Without this rebalancing, Prairie Island Unit 1 is projected to be overfunded. The total accrual may not change, but the required funding for each unit would have to be higher than it is proposed in this filing. It also should be noted that the Escrow must be "poured over" at the end of operations to the external trust fund if it is deemed necessary for decommissioning. The investments can be poured over in kind and would not be required to be cashed out in order to do the pour over. The rebalancing would entail a transfer of funds from Prairie Island Unit 1 to the Prairie Island Unit 2 and Monticello Escrow accounts to reflect a more even distribution of funds between the accounts based on their remaining operating licenses. The transfers necessary to rebalance are different for each cost estimate scenario, although no transfer is necessary for the 36-year cost scenario.

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[13] *In the Matter of Northern States Power Company d/b/a Xcel Energy 2009 Nuclear Plant Decommissioning Accrual*, Docket No. E-002/M-08-1201, ORDER APPROVING DECOMMISSIONING PLAN, AS MODIFIED, AND REQUIRING REFUND PROPOSAL (June 12, 2009).

[14] Includes escrow account.

5. *Recovery Period*

A key assumption in determining the decommissioning accrual is the recovery period over which the customers will fund life of the operating licenses. All of the Company's nuclear production units now have licenses which will take them to a 60-year operating life. The remaining recovery periods for decommissioning as of January 1, 2012 are 18.75 years for Monticello, 21.8 years for Prairie Island Unit 1, and 22.8 for Prairie Island Unit 2.

D. Current Fund Balances

Annually, the Company reports the balances in the various funds in either this petition or a separate letter. The balances for both the Qualified Trust and the Escrow for the Minnesota jurisdiction are discussed below.

1. *Qualified Trust*

As of August 31, 2011, the Qualified Trust book value balance for all three operating units was a total of $921,215,545 for the Minnesota jurisdiction. The Monticello unit had a fund balance of $347,110,688. Prairie Island Unit 1 had a fund balance of $278,087,500. Prairie Island Unit 2 had a fund balance of $296,017,357. A detailed presentation of each unit's balances is presented in Schedule E.

2. *Escrow*

Currently, as of August 31, 2011, the Escrow book value balance for all three operating units was a total of $86,164,271 for the Minnesota jurisdiction. Prairie Island Unit 1 had a fund balance of $37,835,994. Prairie Island 2 had a fund balance of $48,328,277. There is currently no balance in the Escrow for the Minnesota jurisdiction set aside for the Monticello plant as the balance was refunded to customers in 2009. A detailed presentation of each unit's balance is presented in Schedule F.

3. *Theoretical Fund Balance*

In the 1999 filing, the Commission approved the use of a theoretical fund balance that accounts for some of the unrealized activity held in both of the external funds. The Commission supported this conclusion based on the fact that the external funds have been active for over ten years and the performance in the 1990's had exceeded expectations. The use of the theoretical fund balance began because it was felt that incorporating some of the unrealized activities would lead to a more accurate accrual estimate. Due to current market conditions, we believe the previous method of calculation is no longer the preferred method to use in the calculation of accrual estimates. The current forward-looking economic and market conditions warrant reconsideration of historically derived earnings rates.

A pre-tax time-weighted annual return of 4.5% for the Qualified Trust and 3.3% for the Escrow was used to calculate the theoretical fund balance for this filing. The balances were derived at the Minnesota jurisdictional level and a comparison to the actual depreciation reserve amounts forecasted forward to December 31, 2011 is shown in Schedule G. The total theoretical trust fund balances for all three operating units was a total of $984,149,255 for the Minnesota jurisdiction. The Monticello unit had a fund balance of $340,115,704. Prairie Island Unit 1 had a fund balance of $306,034,358. Prairie Island Unit 2 had a fund balance of $337,999,193.

The Company compared its theoretical calculation to the market value of the funds as of August 31, 2011. The total external fund balances (before considering a potential rebalancing of the Escrow should a cost estimate scenario longer than 36 years be approved by the Commission) as of August 31, 2011 for all three operating units was a total of $999,747,193 for the Minnesota jurisdiction. The Monticello unit had a fund balance of $341,711,695. Prairie Island Unit 1 had a fund balance of $313,865,267. Prairie Island Unit 2 had a fund balance of $344,170,231. As can be seen, the actual trust fund balances are higher than those calculated for the theoretical fund balance. Therefore, we used the actual market value as of the date of analysis (August 31, 2011) as it reflects the economic and market conditions in play while completing the analysis for forward looking escalation, inflation, and earnings rates.

Using the current market value is consistent with forward looking market conditions and will provide the most justifiable and proper accrual estimate at this time. However, with market conditions continuously changing, a different representation of fund balances may be appropriate in the future. The Company will continue to assess alternative methods to use and will present any alternative methods in subsequent decommissioning filings as appropriate.

E. Accrual Calculation

The decommissioning accrual is an annuity calculation based on the yearly expenditures, in nominal dollars, provided for each cost estimate scenario. The cost estimate is jurisdictionalized for Minnesota retail customers using 74.0346% as presented in the current Minnesota rate case.[15] The escalation rate is used to inflate the jurisdictional cost estimate to the future years and the earnings rate is used to present value those future dollars back to the start of decommissioning. Then an annuity is factored such that when added to the current fund balance along with an assumed interest that will result in this present value at decommissioning amount.

[15] Minnesota Electric Retail Rate Case, filed November 3, 2010, Docket No. E002/GR-10-971.

The annuity calculation was repeated for each of the five cost estimate scenarios and resulted in the various 2013 accruals on Table 1 of this Petition.

Tables have been provided in Schedule H for the details surrounding the proposed accrual calculation. These tables demonstrate that the amount accrued, with the levelized earnings rate, will result in the proper funds to pay for the inflated future costs for each cost estimate scenario. The end goal of this calculation is to have each unit's fund go to zero in the last year of decommissioning activity. As shown in our analysis, Schedule H, there are a range of overall contributions necessary to meet the future needs to decommission all three units depending on which ISFSI operating period is chosen.

V. Application of DOE Settlement Proceeds to Fund the Accrual

On August 5, 2011, and with corrections dated August 12, 2011, the Company submitted its petition to the Commission for an Order approving a credit mechanism for funds received pursuant to a Settlement ("Settlement") with the DOE. The Settlement settled claims for lawsuits brought by the Company for the DOE's failure to take spent nuclear fuel from Monticello and Prairie Island pursuant to the terms of the Standard Contracts.[16]

The Settlement resulted in an initial payment of approximately $100 million to cover damages awarded through the end of 2008. The Settlement also provides a mechanism for the Company to recover its spent nuclear fuel storage damages from January 1, 2009 through December 31, 2013 on a timely basis without pursuit of further litigation. We expect that the additional damage payments will be approximately $98 million on a total Company basis, or approximately $72.5 million on a Minnesota retail jurisdictional basis. The first supplemental payment, covering 2009 and 2010 damages, is expected to be received in the first quarter of 2012. Payments covering the qualified costs incurred by the Company in 2011, 2012, and 2013 are expected to be received by year end of 2012, 2013, and 2014 respectively (assuming the claim amounts are resolved without the need for binding arbitration and the attendant delay). Table 4 below outlines the timeframe pursuant to which the damages were incurred, the estimated payment amount, the estimated Minnesota jurisdictional amount, and the date the Company anticipates DOE will make the payment.

[16] Under the Nuclear Waste Policy Act and subsequent regulations, utilities are required to enter into Standard Contracts for Disposal of Spent Nuclear Fuel ("Standard Contracts"). 10 C.F.R. § 961.11 (2010). In exchange for the DOE's commitment to dispose of the spent nuclear fuel, utilities contribute 1.0 mil for every kilowatt-hour of electricity generated by their nuclear power plants to the Nuclear Waste Fund ("NWF"). 42 U.S.C. § 10222(a)(2). Pursuant to the Standard Contracts, the DOE was required to take title to, transport, and dispose of the spent nuclear fuel beginning no later than January 31, 1998. 42 U.S.C. § 1022(a)(5)(B). The DOE has not accepted any spent nuclear fuel to this point.

Table 4: Future DOE Settlement Payments

Damages Period	Payment Amount	MN Retail Jurisdiction	Payment Date
2009-2010	$15,000,000	$10,997,453	1st Quarter 2012
2011	$25,000,000	$18,539,578	Yearend 2012
2012	$31,000,000	$22,989,077	Yearend 2013
2013	$27,000,000	$20,022,744	Yearend 2014

On November 10, 2011, the Commission approved a methodology to credit the Settlement dollars received from the DOE to customers through 2013 as a one-time bill credit.[17] The Company does not seek reconsideration of the Commission's order, but requests the Commission modify its order in Docket M-11-807 to credit customers by funding the 2013 and 2014 nuclear decommissioning accruals from the Settlement proceeds received for damages incurred in 2011 and 2012.[18]

Since there is a direct correlation between the funds being received from the DOE Settlement being for the government's failure to remove the spent fuel from our nuclear plant sites and the intent of this filing – to make sure adequate funds are available to decommission the nuclear sites and safely store the spent fuel until the government removes it, we are providing an analysis that includes the use of the DOE Settlement funds for Commission consideration. Our analysis includes two scenarios, both assuming a 2013 accrual start date and both based on using the yearend funding we anticipate receiving in 2012, 2013, and 2014 only. Neither of the scenarios includes any use of the initial Settlement amount received for pre-2008 damages or the second award expected in early 2012 covering 2009 and 2010 damages.

<u>Scenario 1 – Partial Application of DOE Funds, Credit Remaining Amount</u>
The first scenario assumes that the $13.6 million accruals in 2013 and 2014 would be satisfied by transferring $13.6 million of the 2012 and 2013 year-end payments received from the DOE to the Escrow. The remaining amount each year would be credited to customers via the method determined by the Commission in Docket No. E002/M-11-807. Table 5 below shows the estimated Minnesota retail

[17] *In the Matter of a Petition by Xcel Energy for Approval of a Credit Mechanism for a Department of Energy Settlement Payment with Deferred Accounting*, Docket No. E002/M-11-807.

[18] The present decommissioning study was not available at the time the Company filed its petition in Docket M-11-807 or to present to the Commission at the November 10, 2011 hearing.

jurisdiction's amount of that settlement payment, the annual accruals and the estimated amount of the DOE Settlement to be credited to customers.

Table 5: Scenario 1 – Partial Application with Credit of Remaining Amount

Year DOE Payment Received	Estimated DOE Settlement Amount[19]	Accrual Year	Annual Accrual	Estimated Amount to be Credited to Customers
2012	$18,539,578	2013	$13,563,239	$4,976,399
2013	$22,989,077	2014	$13,563,239	$9,415,838
2014	$20,022,744	2015	$13,563,239[20]	$6,449,505

The next Triennial Decommissioning filing is due in October 2014, which would set a new accrual amount for 2015. To the extent the current Settlement with the federal government is extended beyond 2013, use of future Settlement proceeds could be used to offset/eliminate the new accrual amount and the remaining amount could continue to be credited to customers (as shown in Table 5). Alternatively, the new accrual amount could be included in a future test year budget and the crediting of the full DOE Settlement amounts could resume.

<u>Scenario 2 – Apply Full Amount of DOE Funds Received</u>
The second scenario calculates a 2013 accrual amount based on transferring all three DOE Settlement payments expected in late 2012, 2013 and 2014 to the nuclear decommissioning fund. In this scenario, the 2013 accrual would be fully covered until 2015, the next decommissioning filing and the estimated new 2015 accrual - based on the information available today - would be reduced to approximately $10.1 million. As with the first scenario, the full amount of the initial and early 2012 Settlement payments of approximately $100 million and $11 million would be credited to customers. In addition, to the extent the DOE Settlement is extended between the parties beyond the current agreement through 2013, future DOE Settlement proceeds could be used to offset future accruals and additional accruals from customers may not be necessary.

If the Commission authorizes use of the DOE funds as recommended by the Company, the Company would work with the Commission to transfer the funds in such a way as to eliminate any income tax consequences and make sure the full amounts are available for crediting to customers. The Company assumes that it will not have to recognize any taxable income and thus no deferred tax asset. We will

[19] Minnesota retail jurisdiction only.
[20] For illustrative purposes, we include the 2013 accrual for 2015.

track this contribution as non-taxable such that when the contribution is either credited or poured over, the Company will not receive a tax deduction. Thus, no deferred tax asset will be necessary.[21]

Approval of these requests will ensure that the decommissioning fund is adequately funded over the next triennial period and will mitigate, possibly eliminate a rate increase on customers. Funding the accrual with future DOE payments avoids the need to include the accrual to fund used fuel storage and decommissioning costs in a future rate case at the same time credits are being issued to customers for DOE settlement payments to store used nuclear fuel. Because the decommissioning fund is necessary to address the removal of spent nuclear fuel and the settlement payments are due to the storage of spent nuclear fuel on site, the use of the DOE payments results in some matching of costs and revenues related to nuclear generation and used fuel storage. The use of DOE settlement payments to fund the accrual along with the setting of a new accrual amount can be revisited in the next decommissioning study to be filed in 2014, at which time an extension of any DOE Settlement beyond 2013 also may be known.

We propose that the Commission's currently approved accrual amount remain in effect while the Commission reviews the current decommissioning fund accrual and that the new accrual begin January 1, 2013. These amounts would then be included in the next rate case, currently slated for filing in November 2012 with a 2013 test year, if the Commission determines not to apply the DOE Settlement funds to the accrual. This approach is consistent with recent decommissioning fund filings, where significant variations in the accrual amounts were reflected starting on a date corresponding to a new test year.[22] In addition, this approach is consistent with the legislative direction that the Commission approved accrual amounts be included in a rate case filing.[23]

VI. Effect of the Change on Rates

This instant Petition will not impact rates, the price of Xcel Energy electric service, or the terms and conditions of service. Rather, the changes will reflect the way Xcel Energy recognizes the depreciation expense for nuclear decommissioning for the relevant assets. These changes in the accrual expense approved by the Commission would be reflected in rates set in the Company's next rate case.

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[21] If the contributions are included as part of general rates, then the revenue collected in general rates would be taxable because the contributions would not be currently deductible for income tax purposes. A deferred tax asset would be set up with each year's contribution. The deferred tax asset is part of rate base and would be decreased when either refunds are made from the Escrow or the fund is poured over to the Qualified Trust.

[22] *See In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the 2005 Review of Nuclear Plant Decommissioning*, MPUC Docket *No. E002/M-05-1648 and In the Matter of Northern States Power Company d/b/a Xcel Energy 2009 Nuclear Plant Decommissioning Accrual,* MPUC Docket No. E002/M-08-1201.

[23] Minn. Stat. § 216B.2445, subd. 2 (2011).

However, using the DOE Settlement funds as proposed to fund the accrual results in no impact on future (2013 & 2014) rates.

In addition to cost estimates of decommissioning the plants assuming the used fuel is stored on site for 60 years, 100 years, and 200 years, Subdivision 1 (b) of Minn. Stat. §216B.2445 also requires the inclusion of a estimated ratepayer impact for each of the assumed periods. A rate impact is defined as the financial effect on utility rates of implementing a particular business or policy decision. For this petition we calculated the rate impact to each of the customer classes on a $/kWh increase. This was done by allocating the estimated 2013 accruals for the various scenarios (36-year, 60-year, 100-year, and 200-year w/o repackaging) to the customer classes using the most recent Class Cost of Service Study.

The class allocation process used the same stratification methodology approved by the Commission in Docket No. E002/M-11-807 to return the DOE Settlement dollars for used fuel storage to customers. This included an approximate 19% weight to capacity and an 82% weight to energy usage. The 2013 accrual was then divided by the energy each class used over a previous 12 month period to determine a $/kWh that would be required for that class to collect its portion of the 2013 accrual.

The results of this calculation are expressed in $/month for an average customer in class as shown in Table 6 below for the 60-year, 100-year and two 200-year scenarios. (See Schedule I for information supporting the Rate Impact Calculation.) Because the total accrual for the 36-year and 60-year scenarios are similar, we anticipate similar rate impacts for the 36-year scenario as for the 60-year scenario.

Table 6: Rate Impact

Average Customer Monthly Amount	Residential	C&I Non-Demand	C&I Demand	Lighting
60 year	**$0.30**	**$0.48**	**$16.44**	**$0.53**
100 year	**$0.35**	**$0.56**	**$19.04**	**$0.61**
200 Year (w/o repackaging)	**$0.38**	**$0.60**	**$20.60**	**$0.66**
200 Year (with repackaging)	**$0.43**	**$0.69**	**$23.56**	**$0.76**

Use of the DOE Settlement dollars from payments 3, 4 and 5, in part as presented in DOE Scenario 1, or in whole as presented in DOE Scenario 2, both negate the need for an accrual in 2013 and 2014 and thus do not result in any new rate impact to customers. Implementation of DOE Scenario 1 as recommended also results in a DOE credit to customers in each year, albeit at a reduced amount. Implementation of DOE Scenario 2 would not result in a DOE credit to customers in 2013 or 2014.

In October 2014, the next Triennial Nuclear Decommissioning study will be updated and a new accrual determined based on then current market conditions and assumptions, and a new rate impact will be calculated. If the DOE Settlement is extended beyond its current end date of 2013, future DOE Settlement dollars might be available to mitigate, or potentially eliminate, the need for an additional accrual from customers – either mitigating or eliminating a new rate impact to customers.

VII. End-of-Life Nuclear Fuel

The Company recommends an increase to the annual accrual for end-of-life ("EOL") nuclear fuel for this triennial filing. This is an internal accrual to depreciate future nuclear fuel costs. The Company is proposing to change the 2013 accrual based on the new EOL factors discussed in Schedule J. This is consistent with the presentation of other potential changes in this filing. The annual accrual for 2013 is requested to be $2,022,113. This is an increase of $171,091 over the accrual based on the factors approved in the last triennial filing. All of the numbers for the end-of-life nuclear fuel accrual are for the Minnesota jurisdiction. This recommended increase stems mainly from an update in the estimates of the cost of the final fuel at shutdown. The 2013 accrual worksheet detailing the calculation is included in Schedule J. The internal rate of return should be revised for the 2013 accrual to coincide with the new authorized rate of return from the 2010 Minnesota Electric Rate Case.

VIII. Premature Risk Investigation

In Docket No. E002/D-79-956, the Commission requested that an annual report be submitted to investigate the risks of premature decommissioning and to periodically report the findings to the Commission. In the Commission's Order on the last triennial decommissioning filing, the Commission granted the Company's request to require updating of the risks of nuclear decommissioning at times when material changes occur in the risk or in the risk mitigating coverages, but directed that the Company continue to be required to provide an investigation of premature risk in its triennial nuclear decommissioning filings.[24] Consistent with the Commission's prior

[24] *In the Matter of Northern States Power Company d/b/a Xcel Energy 2009 Nuclear Plant Decommissioning Accrual,* Docket No. E002/M-08-1201, Order Approving Decommissioning Plan, As Modified, and Requiring Refund Proposal (June 12, 2009).

orders, our investigation included the following aspects of the risks of premature decommissioning:

- *The availability of commercial insurance.*
- *The availability of electric industry co-insurance.*
- *Any programs, which may be proposed, mandated, or administered by the NRC or any other United States Government agency.*
- *Specific detailed information pertaining to any steps Xcel Energy has taken to minimize any possible loss, which may occur as a result of premature decommissioning.*
- *Xcel Energy's ability to withstand possible economic and financial trauma, which may be associated with premature decommissioning.*

Schedule K contains the annual response to that request. It addresses accident and non-accident related premature decommissioning of nuclear generating facilities. Presently, insurance is unavailable for non-accident related premature decommissioning such as those caused by regulatory directives. Therefore, the insurance analysis deals with accidents.

Xcel Energy property insurance coverage of $2.25 billion would largely offset the potential impact of an accident-related decommissioning. Although accident-related decommissioning expenses are significant, the length of time involved in a clean-up process, insurance payments, tax deductibility of expenses, and related rate relief would affect the yearly expense. Although accident related premature decommissioning would affect both the Company and its customers, it is anticipated that, with acceptable regulatory decisions, the financial integrity of the Company would be maintained.

IX. Asset Retirement Obligation

The implementation of the Statement of Financial Accounting Standards No. 143 ("SFAS 143"), *Accounting for Asset Retirement Obligations* ("ARO") in January of 2003 brought some changes to the accrual accounting for decommissioning. Financial Accounting Standards Board ("FASB") Interpretation No. 47 ("FIN 47"), *Accounting for Conditional Asset Retirement Obligations* was released in March 2005. This Interpretation of the conditionality of an ARO has resulted in some additional accounting analysis for many of the fixed assets at Xcel Energy. Nuclear decommissioning was never assumed to be conditional in nature, thus the ARO accounting for nuclear decommissioning established in 2003 is unaffected by this Interpretation. Nonetheless, a summary of the ARO accounting for nuclear decommissioning is included in Schedule L for reference.

X. Conclusion

In this filing, Xcel Energy proposes that the decommissioning recovery period associated with Monticello remain the same, concurrent with the current operating license. This takes into account an increase in the recovery period for Monticello, which has previously been approved. We recommend that the current recovery period used for Prairie Island Unit 1 and Prairie Island Unit 2 be extended to take into account the recently approved renewed licenses that allow operations until 2033 for Unit 1 and 2034 for Unit 2.

Xcel Energy recommends that the accrual be set for $13.6 million beginning January 1, 2013 based on the 36-year scenario allowing the Commission time to undertake a complete and thorough review of the filing. The Company proposes that future settlement payments received from the DOE be used to fund the accrual expense and that amounts received in any year greater than the accrual expense be credited to customers consistent with the Commission's decision in Docket No. E002/M-11-807. In the alternative, the Company will include the accrual increase in its next rate case with a 2013 test year. The Company also requests that the end-of-life nuclear fuel accrual amount be set at $2.0 million.

This submittal also satisfies the Commission's requirement to present an investigation of the aspects of the risks of premature decommissioning in years when a full nuclear decommissioning study is completed or when material changes to the risks or mitigating coverage for these risks take place.

XI. Miscellaneous Information

Pursuant to Minn. R. 7829.0700, subpt. 2, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

Kari L. Valley
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401

SaGonna Thompson
Records Specialist
Xcel Energy
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Minneapolis, MN 55401

XII. Proprietary Information

This filing, including all schedules and studies, does not contain any proprietary information.

XIII. Supporting Documents

The following supporting schedules have been included for filing requirement purposes and for additional support to the recommended changes:

Supporting Schedules

A	Cost Estimate Scenarios
B	NRC Minimum Calculations
C	Escalation Analysis 2011
D	External Fund Analysis 2011
E	Qualified Trust Analysis, Statements and Balances
F	Escrow Analysis, Statements and Balances
G	Theoretical Fund Balance
H	Decommissioning Accrual Recommendations
I	Rate Impact Calculation
J	End of Life Accrual
K	Premature Risk Investigation
L	Asset Retirement Obligation

The following supporting studies have been included for filing requirement purposes and for additional support to the recommended changes:

Supporting Studies

M	Decommissioning Cost Analysis for the Monticello Nuclear Generating Plant
N	Decommissioning Cost Analysis for the Prairie Island Nuclear Generating Plant

The following are the acronyms used in this petition:

Acronyms

ARO	Asset Retirement Obligation
BRC	Blue Ribbon Commission
DECON	Prompt Removal and Dismantlement

Acronyms

DER	Minnesota Division of Energy Resources
DOE	United States Department of Energy
DOR	Minnesota Department of Revenue
EOL	End of Life
FASB	Financial Accounting Standards Board
FIN 47	Financial Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*
ISFSI	Independent Spent Fuel Storage Installation or Dry Cask Storage
MPUC	Minnesota Public Utilities Commission
NRC	Nuclear Regulatory Commission
PGA	Pacific Global Advisors
SFAS 143	Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*
TLG	TLG Services, Inc.

State of Minnesota
Before the
Minnesota Public Utilities Commission

Ellen Anderson	Chair
David Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR APPROVAL OF THE 2012-2014 TRIENNIAL NUCLEAR DECOMMISSIONING ACCRUAL

DOCKET NO. E002/M-11-939

SUMMARY

SUMMARY OF FILING

Please take notice that on November 30, 2011, Northern States Power Company ("Xcel Energy" or the "Company"), a Minnesota corporation filed with the Minnesota Public Utilities Commission (the "Commission") its petition for approval of its *Triennial Nuclear Decommissioning Accrual*. In this Petition the Company requests the Commission approve our decommissioning study and assumptions as reasonably approximating the amount of funds necessary to support decommissioning at the end of our nuclear facilities' operating lives; approve an annual accrual of approximately $13.6 million starting January 1, 2013; and apply a portion of future settlement payments received from the Department of Energy ("DOE") to the accrual, eliminating the need to begin charging customers to fund the deficit, and crediting the remainder of the Settlement funds to customers. The Company also requests that the 2013 accrual for end-of-life nuclear fuel be set at $2 million for the Minnesota jurisdiction, which results in an increase of $171,091. The Company requests January 1, 2013 as the effective date for the proposed accrual amounts. The petition fully complies with the new requirements of Minn. Stat. § 216B.2445 and includes a discussion of the premature decommissioning risks as required.

A copy of the filing can be found on xcelenergy.com, About Us > Rates & Regulations > Regulatory Filings > Minnesota Triennial Nuclear Decommissioning.