MINNESOTA DEPARTMENT OF COMMERCE

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October 10, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota, 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E,G999/CI-13-626

Dear Dr. Haar:

On May 16, 2014, the Minnesota Public Utilities Commission (Commission) issued its second *Notice of Comment Period on Decommissioning Cost Investigation*. Attached are the Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in this matter.

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ CRAIG ADDONIZIO
Financial Analyst

CA/ja
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. E,G999/CI-13-626

I. INTRODUCTION AND BACKGROUND

In its July 31, 2013 Order on Minnesota Power's 2012 Remaining Lives Depreciation Petition, the Minnesota Public Utilities Commission (Commission) opened the instant Docket to review decommissioning policies related to depreciation expense, including the calculation of the salvage portion of depreciation expense.

On March 6, 2014, the Commission issued a *Notice of Comment Period on Decommissioning Cost Investigation* in which it requested that utility companies provide explanations of their respective decommissioning practices in Minnesota and other jurisdictions, as well as justifications for the use of decommissioning probabilities. The Commission's Notice also allowed for comments on the utilities' submissions.

On April 7, 2014, several utilities filed Comments in response to the Commission's Notice.

On May 7, 2014, the Minnesota Department of Commerce (the Department) filed Comments (Initial Comments) that attempted to summarize and analyze the utilities' Comments. As discussed further below, in its Initial Comments, the Department concluded that there are two main sources of uncertainty with respect to decommissioning costs: timing and amount. Because the lives of generating plants are frequently extended, it is often unclear whether a plant with a long remaining life will be decommissioned at the end of its current remaining life. The Department's analysis in its Initial Comments demonstrated that if a plant's decommissioning cost is known and certain (regardless of the timing of decommissioning), then uncertainty in the timing of decommissioning could justify some use of a decommissioning probability. However, decommissioning costs are not known and certain in advance. Given the uncertainties of both the timing and amount of decommissioning costs, the Department requested that utilities provide more information about changes in decommissioning costs over time to assess further how decommissioning probabilities should be used in depreciation petitions.

Specifically, the Department requested that utilities provide additional data in order to determine if there is a predictable pattern in changes to decommissioning cost estimates over time. More specifically, the Department requested that utilities explain whether they adjust their decommissioning cost estimates to account for expected inflation, and provide historical decommissioning cost estimates, decommissioning accruals, and decommissioning probabilities. The following four utilities provided the requested data:

- Minnesota Power (MP)
- Xcel Energy (Xcel)
- Otter Tail Power Company (Otter Tail)
- Interstate Power & Light (IPL)

The Department's analysis of the utilities' data is provided below.

II. DEPARTMENT ANALYSIS

The Department's analysis in its Initial Comments indicated that when decommissioning costs are certain, but timing is uncertain, the use of a decommissioning probability can be justified. The Department considered an example of a hypothetical plant with 30-year remaining life, and a 10 percent chance of receiving no life extension, a 40 percent chance of receiving a 15-year life extension and a 50 percent chance of receiving a 30-year life extension, with a known decommissioning cost of $10 million.[1] Table 1 below, which is a reproduction of Table 1 from the Department's Initial Comments, uses these life-extension probabilities to calculate a decommissioning probability that would best spread estimated decommissioning costs evenly over time.

[1] The Department notes that some of the figures in the text of the Department's initial comments were not accurate; these figures are corrected in the text above.

Table 1
Reproduction of Table 1 from Initial Comments
Example 1
Uncertain Timing of Decommissioning with
Certain Decommissioning Costs
($000s)

Scenario	Life Extension	Decomm. Cost	Plant Whole Life	Remaining Life at the End of Year 30	Accumulated Decomm. Cost at End of Year 30	Scenario Probability	Accumulated Decomm. Cost Multiplied by Scenario Probability
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]
1	0	$ 10,000	30	0	$ 10,000	10%	$ 1,000
2	15	10,000	45	15	6,667	40%	2,667
3	30	10,000	60	30	5,000	50%	2,500
						100%	6,167
Weighted 30-year Removal Cost "Target"							6,167
Estimated Decommissioning Cost							$ 10,000
Decommissioning Probability							61.7%

The Department notes that, if decommissioning costs are known (certain), then the more likely life extensions are considered to be, the lower is the appropriate decommissioning probability. For example, given a 10 percent chance of no life extensions, a 20 percent chance of a 15-year life extension, and a 70 percent chance of a 30-year life extension in the above example, the appropriate decommissioning probability would be 58.3 percent (as opposed to 61.7 percent, as calculated in Table 1).

However, because decommissioning costs are not known and certain, especially at the beginning of a plant's life, the Department attempted to add uncertainty to its decommissioning cost estimate, as shown in Table 2 below, which is a reproduction of Table 3 from the Department's Initial Comments.

Table 2
Reproduction of Table 3 from Initial Comments
Example 3
Uncertain Timing of Decommissioning with
Uncertain Decommissioning Costs and Weighted Cost Outcomes

Scenario	Life Extension	Decomm. Cost	Plant Whole Life	Remaining Life at the End of Year 30	Accumulated Decomm. Cost at End of Year 30	Probability of Life Extension	Probability of Decomm. Cost	Scenario Probability	Accumulated Decomm. Cost Multiplied by Scenario Probability
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]=[g]x[h]	[j]=[f]x[i]
1a	0	$ 5,000	30	0	$ 5,000	10.00%	10.00%	1.00%	$ 50
1b	0	10,000	30	0	10,000	10.00%	50.00%	5.00%	500
1c	0	15,000	30	0	15,000	10.00%	40.00%	4.00%	600
Subtotal								10.00%	1,150
2a	15	5,000	45	15	3,333	40.00%	10.00%	4.00%	133
2b	15	10,000	45	15	6,667	40.00%	50.00%	20.00%	1,333
2c	15	15,000	45	15	10,000	40.00%	40.00%	16.00%	1,600
Subtotal								40.00%	3,067
3a	30	5,000	60	30	2,500	50.00%	10.00%	5.00%	125
3b	30	10,000	60	30	5,000	50.00%	50.00%	25.00%	1,250
3c	30	15,000	60	30	7,500	50.00%	40.00%	20.00%	1,500
Subtotal								50.00%	2,875
Total								100.00%	7,092

Weighted 30-year Removal Cost "Target"	7,092
Estimated Decommissioning Cost	$ 10,000
Decommissioning Probability	70.9%

Notes:
[f] = ([c] / 30) * $1,000,000

For each possible life extension, the Department considered three possible cost outcomes, and weighted the two highest cost outcomes more heavily than the lowest cost outcome. Table 2 demonstrates that when the uncertainty in decommissioning costs is accounted for, and cost increases are considered to be more likely than cost decreases, the appropriate decommissioning probability for a plant with an initial 30-year remaining life rises relative to the appropriate decommissioning probability when costs are treated as certain (referring to the 70.9 percent figure, rather than the 61.7 percent figure in Table 1 above).

Based on this analysis, the Department concluded that in order to evaluate whether the use of decommissioning probabilities is reasonable, it needed to analyze how decommissioning cost estimates change over time. For this reason, the Department requested that the utilities provide historical decommissioning estimates, accruals, and probabilities reaching as far back in time as practicable. Xcel, Otter Tail, and MP provided this data going back to 1983, 1980, 2008, respectively. IPL provided decommissioning accruals back to 2006, but provided only its current salvage estimates. Thus, the Department is unable to analyze the trend in IPL's decommissioning estimates.

Additionally, as described in the Department's Initial Comments, Otter Tail adjusts its decommissioning estimates for inflation. In other words, Otter Tail develops a decommissioning cost estimate for each of its plants measured in present-day dollars, and then uses an assumed inflation rate to inflate those estimates to the retirement dates of their respective plants. Thus, it is difficult to analyze the trends in Otter Tail's decommissioning estimates over time without knowing the uninflated estimates and the assumed inflation rates and the remaining lives used to calculate the inflated estimates. The Department was able to gather this data from eDockets back to 1998 from Otter Tail's five-year depreciation studies.

The Department's analysis of this data is described in greater detail in Attachments 1, 2, and 3 to these Comments. In summary, however, despite some limitations in the data, there appears to be a clear upward trend in the decommissioning estimates. Xcel has several plants which have had decommissioning costs built into depreciation since 1983, and the decommissioning cost estimates for these plants have grown by 2.8 percent to 6.0 percent per year over that time, including inflation. The average annual rate of growth in the decommissioning estimates for Otter Tail's plants over the period 1998-2013 has been 7.9 percent to 10.1 percent, including inflation. While growth rates this high are not sustainable over long periods of time, based on these trends, the Department revisited its examples from its Initial Comments, and attempted to reflect growth rates of two to four percent, based on expected inflation.

In Table 2 above, the Department attempted to represent uncertainty in decommissioning costs by creating three cost scenarios, which were assumed to be applicable to all of the timing scenarios. In other words, the high cost was assumed to be the same regardless of whether it was incurred in year 30, year 45, or year 60. Based on the Department's analysis in Attachments 1, 2, and 3, the Department now recognizes that decommissioning cost and timing are correlated, as the longer a plant is in service, the higher its decommissioning cost is likely to be, due to effects of inflation and other factors. The Department therefore revised Example 3 to reflect this correlation. In Table 3 below, instead of assuming fixed low, medium and high cost scenarios, the Department applied four growth rates to the initial decommissioning cost estimate. Thus, the final estimate of decommissioning cost (shown in column [f]) is a function of the growth rate and the plant's whole life.

Table 3
Revised Example 3
Uncertain Timing of Decommissioning with
Uncertain Decommissioning Costs and Weighted Cost Outcomes

Scenario	Life Extension	Initial Decomm. Cost Estimate	Decomm. Cost Growth Rate	Plant Whole Life	Final Decomm. Cost Estimate	Remaining Life at the End of Year 30	Accumulated Decomm. Cost at End of Year 30	Probability of Life Extension	Probability of Decomm. Cost	Scenario Probability	Accumulated Decomm. Cost Multiplied by Scenario Probability
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]=[i]x[j]	[l]=[h]x[k]
1a	0	$ 10,000	0%	30	$ 10,000	0	$ 10,000	10.00%	10.00%	1.00%	$ 100
1b	0	10,000	2%	30	17,758	0	17,758	10.00%	40.00%	4.00%	710
1c	0	10,000	3%	30	23,566	0	23,566	10.00%	40.00%	4.00%	943
1d	0	10,000	4%	30	31,187	0	31,187	10.00%	10.00%	1.00%	312
Subtotal										10.00%	2,065
2a	15	10,000	0%	45	10,000	15	6,667	40.00%	10.00%	4.00%	267
2b	15	10,000	2%	45	23,901	15	15,934	40.00%	40.00%	16.00%	2,549
2c	15	10,000	3%	45	36,715	15	24,476	40.00%	40.00%	16.00%	3,916
2d	15	10,000	4%	45	56,165	15	37,443	40.00%	10.00%	4.00%	1,498
Subtotal										40.00%	6,732
3a	30	10,000	0%	60	10,000	30	5,000	50.00%	10.00%	5.00%	250
3b	30	10,000	2%	60	32,167	30	16,083	50.00%	40.00%	20.00%	3,217
3c	30	10,000	3%	60	57,200	30	28,600	50.00%	40.00%	20.00%	5,720
3d	30	10,000	4%	60	101,150	30	50,575	50.00%	10.00%	5.00%	2,529
Subtotal										50.00%	9,187
Total										100.00%	17,984

Weighted 30-year Removal Cost "Target"	17,984
Estimated Decommissioning Cost	$ 10,000
Decommissioning Probability	179.8%

Notes:
[f]=[c]x(1+[d])^([e]-1)
[h]= ([f] / 30) * $10,000

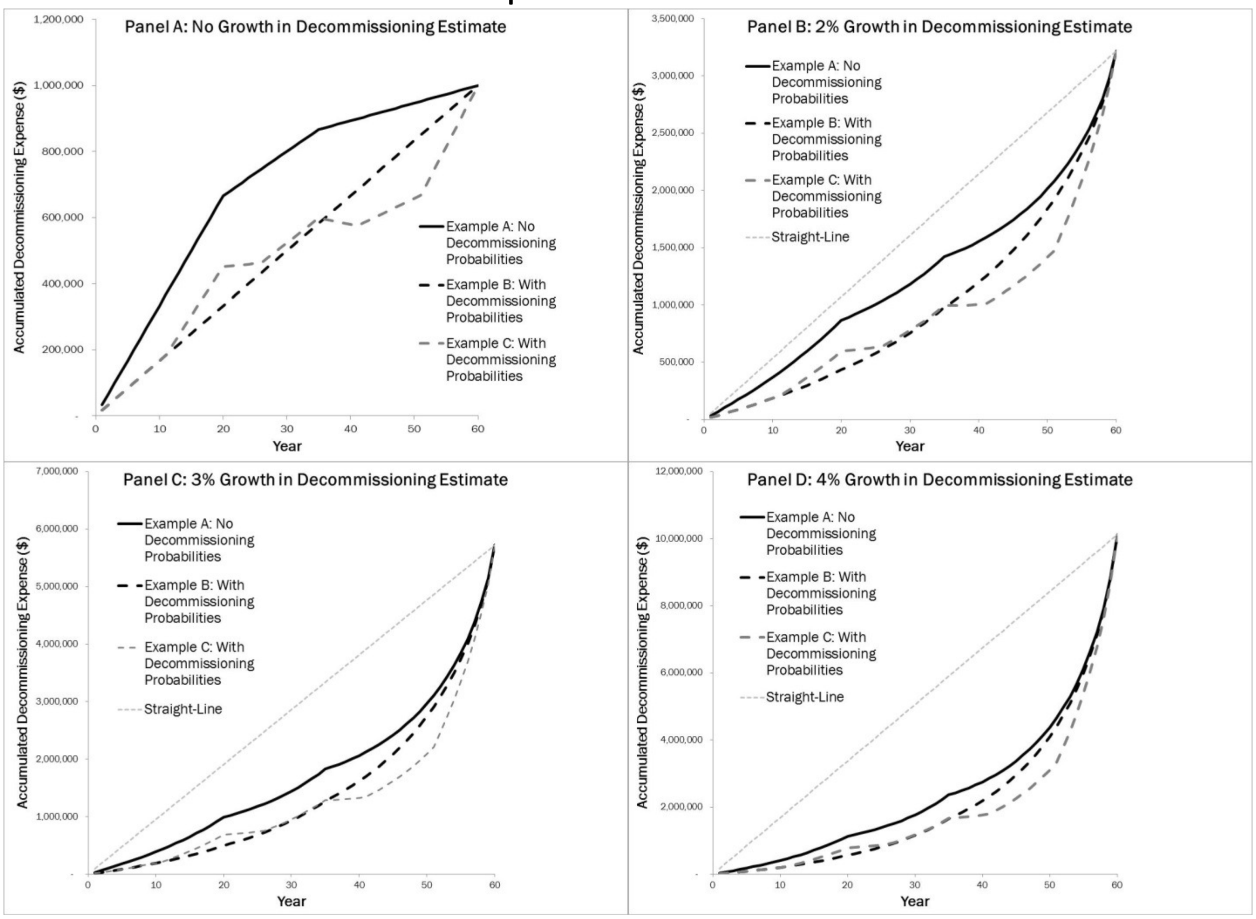
As shown, the introduction of even modest growth in decommissioning costs more than eliminates the need for a decommissioning probability to adjust the current decommissioning cost estimate. In fact, this example shows that it may be appropriate to inflate a plant's current decommissioning estimate (measured in current dollars) in order to achieve straight-line accruals in the face of potential growth. This approach would be, in effect, equivalent to Otter Tail's practice of adjusting its decommissioning estimates upwards to account for expected inflation.

The Department is hesitant to advocate for this position, however. The Department notes that the final decommissioning cost estimates in column [f] are inflated into future dollars. In other words, if the initial decommissioning cost estimates are measured in 2014 dollars, then the final cost estimate in scenario 3d of $101,150 is measured in 2074 dollars. The rest of the calculations in scenario 3d assume that this $101,150 is expensed in equal installments every year from 2014 to 2074. This means that ratepayers in 2014 will pay the same nominal amount as ratepayers in 2074, but much more in real terms. While this result may comply with the letter of the Commission's rule requiring straight-line depreciation, it is clearly not the desired effect of that rule.

This issue highlights an important difference between plant depreciation, which is the expensing over time of a known historical cost, and the amortization of estimated decommissioning costs, which is the expensing over time of an unknown future cost. A $100 plant with a ten year life would incur depreciation expense of $10 per year. Thus, ratepayers in year one will pay more for that plant in real terms than ratepayers in year 10, even though both sets of ratepayers will pay the same amount in nominal terms. However, plant additions, which are measured in current dollars, increase depreciation expense and counterbalance much of this real/nominal difference. No such natural counterbalance exists for decommissioning expense.

Figure 1 below demonstrates the effects of various assumptions about the growth of decommissioning costs on accumulated decommissioning expense over time, and is based on the example in Attachment 1 to the Department's Initial Comments. The data in Panel A are taken directly from that example (Panel A is a reproduction of Figure 2 from the Department's Initial Comments). Example A assumes that decommissioning expense is calculated with no decommissioning probabilities, and Examples B and C assume the use of decommissioning probabilities with different rules regarding when to change or update the probabilities. Example B was designed to produce a perfect straight-line accrual over time, while in Example C, decommissioning probabilities are governed by the rules Xcel uses to set its actual decommissioning probabilities (see page 5 of Xcel's April 7, 2014 Comments). Example A appears to over-accumulate decommissioning expense during the first half of the plant's life, and then under-accumulate it during the second half. Thus, Panel A demonstrates that when growth in estimated decommissioning costs is assumed to be zero, decommissioning probabilities are justified.

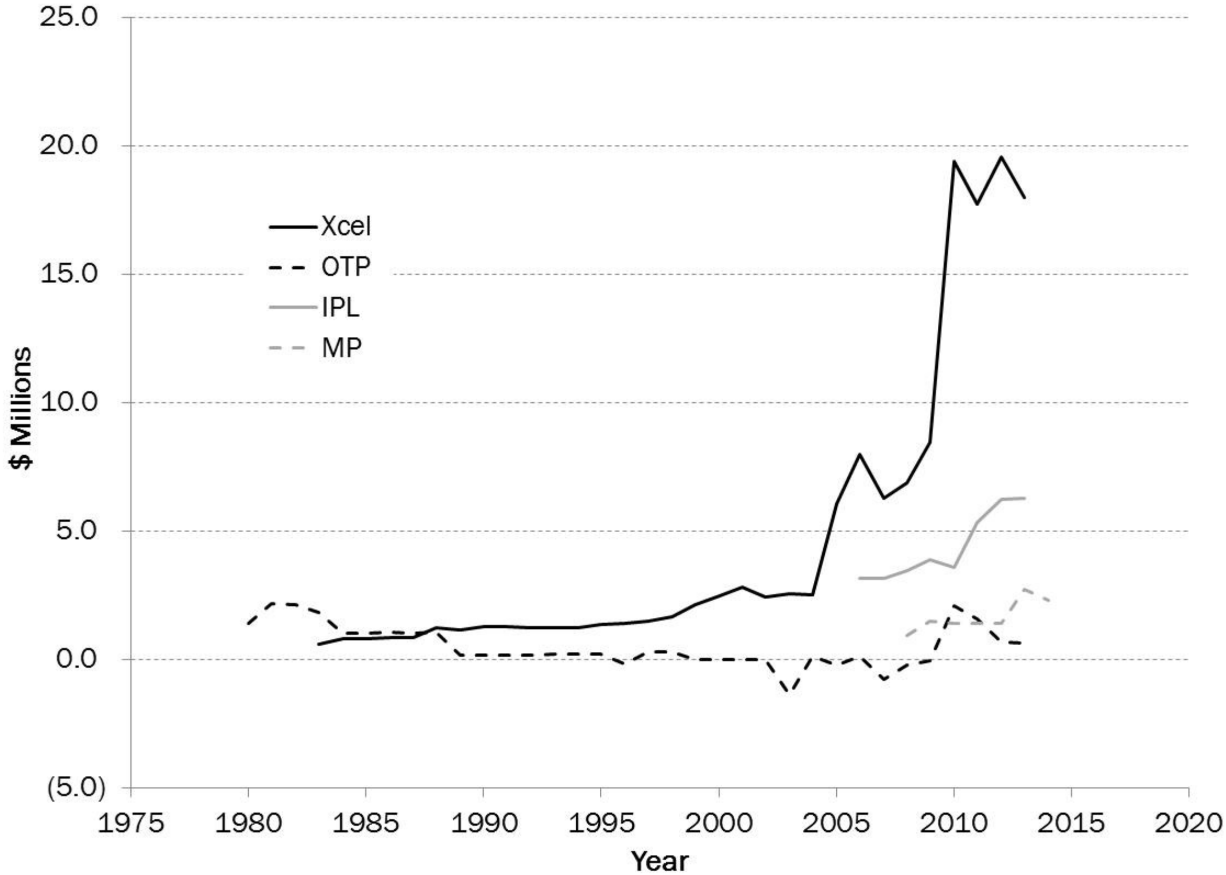
Figure 1
Accumulated Decommissioning Expense
Using Various Decommissioning Probability
Assumptions and Growth Rates



Panels B, C, and D, however, demonstrate that when growth in costs of decommissioning a plant is considered, all three methods tend to under-accrue decommissioning expense early and over-expense it late in order to catch up. However, as described above, some degree of under-accrual may be desirable to ensure that current ratepayers do not pay significantly more in real terms than future ratepayers. Perhaps more importantly, Panels B, C, and D demonstrate that the effects of decommissioning probabilities are largely overwhelmed by the effects of growth in decommissioning cost estimates.

In its initial Comments, the Department stated its desire to analyze the actual historical decommissioning accruals of utilities to determine whether the annual accruals of utilities that use decommissioning probabilities are less volatile than the accruals of those that do. The Department attempted to complete this analysis with the data provided by the utilities in response to the Commission's May 16, 2014 Notice of Comment Period. Figure 2 plots the data provided by utilities.

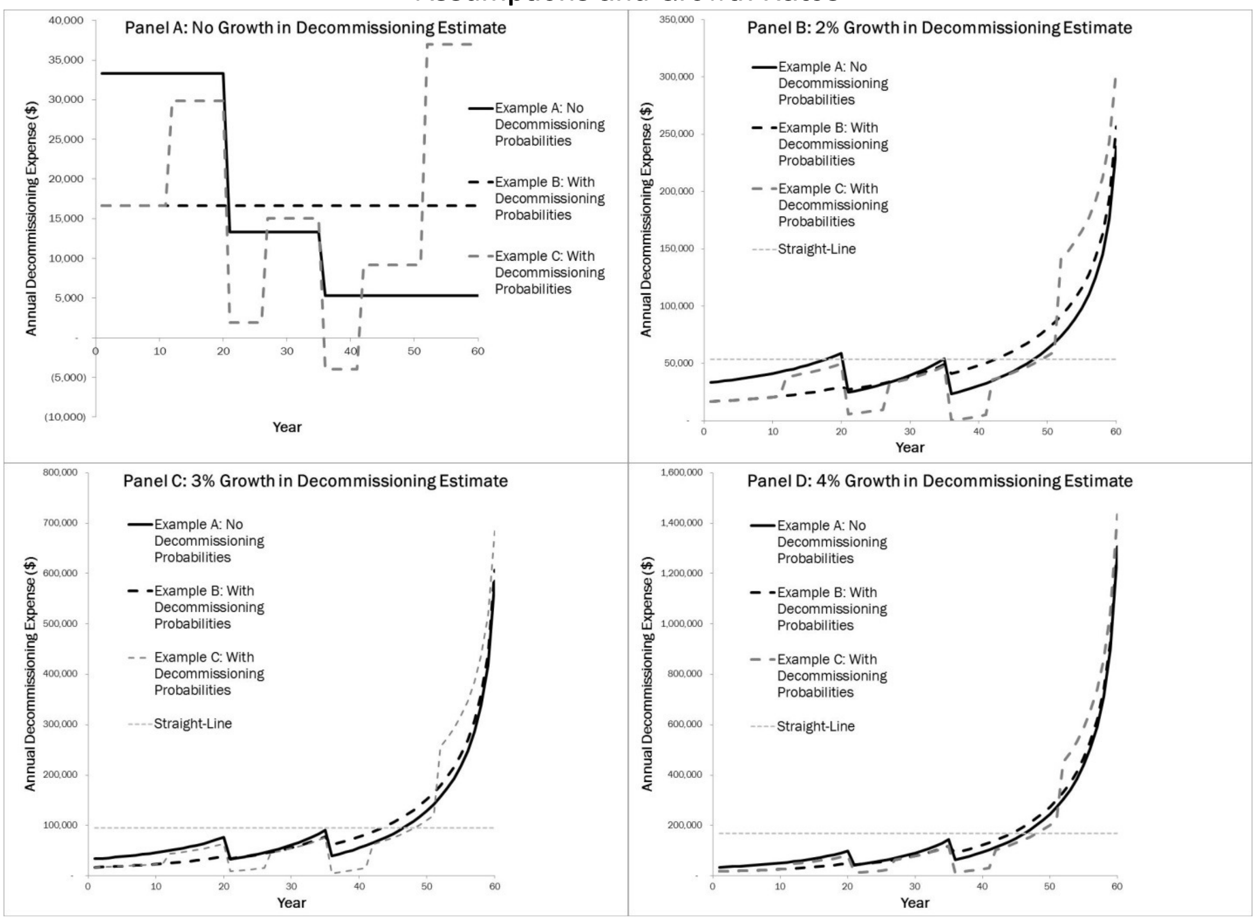
Figure 2
Actual Historical Decommissioning Accruals



As discussed above, MP and IPL provided only seven and eight years of data, respectively, which is not sufficient to draw any meaningful conclusions. Xcel and Otter Tail provided data covering much longer periods than the data MP and IPL provided. Both appear to have relatively smooth accruals until the mid-2000s, at which point Otter Tail's data begins to show some increase in volatility, while Xcel's data indicate significant increases in decommissioning costs. The Department notes that Xcel established decommissioning estimates for many of its plants in 1983, and did not revisit those estimates until 2005. Since 2005, Xcel has been updating its decommissioning estimates regularly, which has resulted in the observed growth. Therefore, Xcel's decommissioning accruals over the period 1983-2005 are not indicative of Xcel's current decommissioning practices, and the increases since 2005 are due more to changes in decommissioning cost estimates than decommissioning probabilities.

The Department therefore reviewed the annual accruals in the examples in Figure 2 above to determine how the introduction of growth rates interacts with decommissioning probabilities to affect accruals. Figure 3 below compares the annual accruals from the examples in Figure 1.

Figure 3
Accumulated Decommissioning Expense
Using Various Decommissioning Probability
Assumptions and Growth Rates



As shown, the effects of growth in the decommissioning cost estimates tend to overwhelm the differences between the examples. However, in Panels B, C, and D, Example A (without decommissioning probabilities) exhibits less volatility in the early years than Example C, and Example A expenses are a slightly smaller portion of total decommissioning cost in the last ten years or so than Examples B and C.

III. CONCLUSION

As described in the Department's Initial Comments, the intent of decommissioning probabilities is to is recognize and account for uncertainty in decommissioning costs when calculating depreciation expense, and smooth the expensing (and recovery) of decommissioning costs over the life of a plant. Based on the Department's analysis, it is not clear that decommissioning probabilities accomplish this goal, and in fact may have the opposite effect. The Department's example, which uses Xcel's rules for managing decommissioning probabilities, indicates that decommissioning expense appears to be more volatile, and results in larger increases late in a plant's life, than the example that does not use decommissioning probabilities. Thus, when growth in decommissioning costs over time is reflected, the Department sees little or no support for the continued use of decommissioning probabilities.

Therefore, the Department recommends that the Commission require utilities to cease using decommissioning probabilities, on a going-forward basis.

If the Commission agrees with this recommendation, it may wish to consider the financial impact this change will have on MP and Xcel in determining whether to require the utilities to make this change before their next rate cases. The Department notes that MP has provided estimates of the impact that elimination of decommissioning probabilities would have on its annual depreciation expense in recent depreciation filings. In Docket No. E015/D-14-318, MP estimated that it would increase depreciation expense by $2.2 million, or roughly 3.5 percent. The Department did not estimate the effect that eliminating decommissioning probabilities would have on Xcel, but notes that, in 2010, Xcel set many of its decommissioning probabilities to 100 percent, and thus only a small number of its plants would be affected by such a change.

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Minnesota Power's Decommissioning Cost Estimates

MP's Decommissioning Cost Estimates and Growth Rates 2008-2014

Year	Boswell Energy Center Unit 1	Boswell Energy Center Unit 2	Boswell Energy Center Unit 3	Boswell Energy Center Unit 4	Boswell Energy Center Common	Laskin Energy Center	Taconite Harbor Energy Center	Total - All Plants	Total - Excluding Tac. Harbor
1999	1,112,314	1,067,535	15,240,693	22,503,732	5,032,654	5,036,724	n/a	n/a	49,993,652
2008	1,173,877	1,130,974	16,083,051	19,242,310	4,427,706	7,382,216	6,634,859	56,074,993	49,440,134
2009	1,659,770	1,599,590	22,616,338	27,071,100	6,219,344	8,574,264	6,634,859	74,375,265	67,740,406
2010	1,659,770	1,599,590	25,144,338	27,071,100	6,219,344	8,574,264	6,634,859	76,903,265	70,268,406
2011	1,659,770	1,599,590	25,144,338	27,071,100	6,219,344	8,574,264	6,634,859	76,903,265	70,268,406
2012	1,659,770	1,599,590	25,144,338	27,071,100	6,219,344	8,574,264	6,634,859	76,903,265	70,268,406
2013	6,314,600	6,443,000	29,575,200	34,394,480	10,131,451	11,444,000	10,896,000	109,198,731	98,302,731
2014	5,685,255	5,685,255	27,013,141	32,798,976	7,407,312	11,568,000	8,039,000	98,196,939	90,157,939
Annualized Growth Rate									
1999-2014	11.5%	11.8%	3.9%	2.5%	2.6%	5.7%	n/a	n/a	4.0%
2008-2014	30.1%	30.9%	9.0%	9.3%	9.0%	7.8%	3.3%	9.8%	10.5%

The table above contains MP's decommissioning estimates for the years 2008-2014, as reported in MP's July 30, 2014 Comments. The Department also added data for 1999 as filed in Docket No. E015/D-99-502 (MP's 1999 Depreciation Petition, its oldest five-year study available on eDockets). The Department calculated the annualized rate of growth in the decommissioning estimate for each plant, as well as the sum of MP's decommissioning estimates across all plants for the periods 1999-2014 and 2008-2014. The decommissioning estimates for all plants are positive, but are sensitive to the start date. As shown, the growth rates for the period 2008-2014 are significantly higher than they are for the period 1999-2014. Over the fifteen year period 1999-2014, MP's decommissioning growth rates range from 2.5 percent to 11.8 percent, and average 4.0 percent across all plants.

Otter Tail's Decommissioning Cost Estimates

Otter Tail's Decommissioning Cost Estimates and Growth Rates 1998-2013

Plant	1998	2003	2008	2013	Annualized Growth Rate
Inflated Dismantlement Estimates					
Hoot Lake Plant Unit 1		265,302			
Hoot Lake Plant Units 2&3		4,301,561	4,618,000	6,707,000	4.5%
Hoot Lake Plant	3,033,881				
Big Stone Plant	6,628,217	4,330,110	8,375,993	8,179,325	1.4%
Coyote Station	4,633,561	2,040,016	4,561,690	7,521,605	3.3%
Uninflated Dismantlement Estimates					
Hoot Lake Plant Unit 1		250,000			
Hoot Lake Plant Units 2&3		2,999,000	4,618,000	7,858,319	10.1%
Hoot Lake Plant	2,526,191				
Big Stone Plant	5,136,864	3,031,767	11,498,443	16,037,006	7.9%
Coyote Station	3,347,315	1,293,388	6,914,000	13,357,202	9.7%

The table above contains Otter Tail's inflated and uninflated decommissioning estimates from various depreciation petitions filed with the Commission. The table reports both the uninflated and inflated decommissioning estimates, and shows that the uninflated cost estimates (i.e. the estimates measured in current dollars) for Big Stone and Coyote Station have been growing by approximately 8-10 percent over the last 15 years.

The Department notes that in 1998, the decommissioning cost estimate for "Hoot Lake Plant" reflects units 1, 2, and 3. In 2003, Otter Tail separated the estimate for unit 1 from the estimate for units 2 and 3, and unit 1 was retired in 2005. Thus, for Hoot Lake, the Department calculated the growth rate only for units 2 and 3, over the period 2003-2013.

Xcel's Decommissioning Cost Estimates

Pages 3 and 4 of this Attachment contains Xcel's decommissioning cost estimates for the years 1983-2013, as reported in Xcel's July 30, 2014 Comments. The Department calculated annualized rates of growth in the decommissioning estimates for each plant. Xcel's data was complicated by several additions to existing plants, as well as fuel conversions at certain plants. Below, the Department explains how it accounted for changes at selected plants.

High Bridge and Riverside

Xcel's High Bridge and Riverside plants were original built in the early 1900s as coal-powered generating stations. Both were replaced with natural gas facilities in the mid-2000s. In Xcel's data, the plants are reclassified from Steam Production to Other Production in the year the new natural gas facilities began operation. The Department calculated growth rates which treat the old and new facilities as the same plant. However, as a result of the refueling, there may be important differences between the plant needing to be decommissioned in 2013 and the plant needing to be decommissioned in 1983. For this reason, the Department also calculated the growth rate for the Steam Production facilities for the period beginning in 1983, and ending in the last year each facility was classified under Steam Production.

Sherco

For the years 1983-1987, Xcel's data includes a Steam Production plant labeled "Sherco." Beginning in 1988, when Unit 3 was added, Xcel's data includes two separate line items labeled "Sherco Units 1&2" and "Sherco Unit 3." The Department treats "Sherco" and "Sherco Units 1&2" as the same plant in calculating an annualized growth rate.

Angus Anson

Xcel's data for 2005 includes a line-item labeled "Angus Anson." Beginning in 2006, the plant was separated into two line-items labeled "Angus Anson Units 2&3" and "Angus Anson Unit 4." During the years 2006-2009, Xcel states that the decommissioning estimate attributed to "Angus Anson Units 2&3" is the estimate for the whole facility. Therefore, the Department sums the two Angus Anson line-items in calculating Angus Anson's growth rate.

Summary

As shown in the table below, except for Xcel's Hydro and Gas Production facilities, the growth rates in the decommissioning estimates for Xcel's plants are positive, ranging from 2.8 percent to 30.9 percent. The Department notes that for a number of plants, the decommissioning estimates cover only the period 2005-2013, and that all of the plant with growth rates greater than ten percent fall in this category. Given the limited amount of data available for these plants, it is difficult to draw strong conclusions.

Xcel's Decommissioning Cost Estimates and Growth Rates
($)

Plant	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Steam Production/Black Dog	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	N/A	N/A
Other Production/Black Dog Unit 5																		
Steam Production/High Bridge	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	N/A	N/A
Other Production/High Bridge																		
Subtotal	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	N/A	N/A
Steam Production/Allen S King	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000
Steam Production/Minnesota Valley	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Steam Production/Pathfinder	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Steam Production/Red Wing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Steam Production/Riverside	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	N/A	N/A
Other Production/Riverside																		
Subtotal	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	N/A	N/A
Steam Production/Sherco	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000													
Steam Production/Sherco Units 1&2						14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	N/A	N/A
Subtotal	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	N/A	N/A
Steam Production/Sherco Unit 3						-	-	-	-	-	-	-	-	-	-	-	N/A	N/A
Steam Production/Wilmarth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other Production/Alliant Tech																		
Other Production/Angus Anson																		
Other Production/Angus Anson Units 2&3																		
Other Production/Angus Anson Unit 4																		
Subtotal																		
Other Production/Blue Lake																		
Other Production/Blue Lake Units 1 thru 4																		
Other Production/Blue Lake Units 7&8																		
Other Production/Granite City																		
Other Production/Inver Hills																		
Other Production/Key City																		
Other Production/United Health																		
Other Production/United Hospital																		
Other Production/West Faribault																		
Other Production/Grand Meadow																		
Other Production/Wind Storage																		
Other Production/Nobles																		
Hydro Production/Hennepin Island											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hydro Production/Lower Dam											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hydro Production/Upper Dam											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hydro Production/St. Croix Falls											N/A	N/A						
Gas Production/6" Pipe											N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Gas Production/Maplewood											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas Production/Sibley											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas Production/Wescott											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas Storage/Wescott											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas Production/Grand Forks																		N/A

Note: Annualized Growth Rates are calculated over the longest possible period for which data is available. For example, the growth rate for Steam Production/Allen King is calculated for the period 1983-2013, while the rate for Steam Production/Sherco Unit 3 is calculated for the period 2005-2013.

Xcel's Decommissioning Cost Estimates and Growth Rates
($)

Plant	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Annualized Growth Rate
Steam Production/Black Dog	N/A	N/A	N/A	N/A	17,830,000	17,830,000	17,830,000	17,830,000	17,830,000	23,786,570	23,786,570	23,786,570	23,786,570	4.5%
Other Production/Black Dog Unit 5					2,610,000	2,610,000	2,610,000	2,610,000	2,610,000	13,493,635	13,493,635	13,493,635	13,493,635	22.8%
Steam Production/High Bridge	N/A	N/A	N/A	N/A	20,000,000	20,000,000	20,000,000	20,000,000						6.6%
Other Production/High Bridge								-	-	11,536,000	11,536,000	11,536,000	11,536,000	0.0%
Subtotal	N/A	N/A	N/A	N/A	20,000,000	20,000,000	20,000,000	20,000,000	N/A	11,536,000	11,536,000	11,536,000	11,536,000	3.5%
Steam Production/Allen S King	6,647,000	6,647,000	6,647,000	6,647,000	18,140,000	18,140,000	18,140,000	18,140,000	18,140,000	33,401,000	33,401,000	33,401,000	33,401,000	5.5%
Steam Production/Minnesota Valley	N/A	N/A	N/A	N/A	10,130,000	10,130,000	10,130,000	10,130,000	10,130,000	13,875,000	13,875,000	13,875,000	N/A	4.6%
Steam Production/Pathfinder	N/A	N/A												
Steam Production/Red Wing	N/A	N/A	N/A	N/A	3,400,000	3,400,000	3,400,000	3,400,000	3,400,000	10,392,000	10,392,000	10,392,000	10,392,000	15.0%
Steam Production/Riverside	N/A	N/A	N/A	N/A	30,650,300	30,650,300	30,650,300	30,650,300	30,650,300					6.8%
Other Production/Riverside									-	32,501,168	32,501,168	32,501,168	32,501,168	
Subtotal	N/A	N/A	N/A	N/A	30,650,300	30,650,300	30,650,300	30,650,300	30,650,300	32,501,168	32,501,168	32,501,168	32,501,168	6.0%
Steam Production/Sherco														
Steam Production/Sherco Units 1&2	N/A	N/A	N/A	N/A	43,320,000	43,320,000	43,320,000	43,320,000	43,320,000	36,236,953	36,236,953	36,236,953	36,236,953	
Subtotal	N/A	N/A	N/A	N/A	43,320,000	43,320,000	43,320,000	43,320,000	43,320,000	36,236,953	36,236,953	36,236,953	36,236,953	3.1%
Steam Production/Sherco Unit 3	N/A	N/A	N/A	N/A	38,340,000	38,340,000	38,340,000	38,340,000	38,340,000	47,856,384	47,856,384	47,856,384	47,856,384	2.8%
Steam Production/Wilmarth	N/A	N/A	N/A	N/A	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	9,373,000	9,373,000	9,373,000	9,373,000	14.2%
Other Production/Alliant Tech					-	-	-	-	-	-	-	-		
Other Production/Angus Anson					1,280,000									
Other Production/Angus Anson Units 2&3						1,280,000	1,280,000	1,280,000	1,280,000	3,249,262	3,249,262	3,249,262	3,249,262	
Other Production/Angus Anson Unit 4					-	-	-	-	-	1,989,208	1,989,208	1,989,208	1,989,208	
Subtotal					1,280,000	1,280,000	1,280,000	1,280,000	1,280,000	5,238,470	5,238,470	5,238,470	5,238,470	19.3%
Other Production/Blue Lake					820,000									
Other Production/Blue Lake Units 1 thru 4						820,000	820,000	820,000	820,000	2,882,769	2,882,769	2,882,769	2,882,769	19.7%
Other Production/Blue Lake Units 7&8					820,000	820,000	820,000	820,000	820,000	2,882,769	2,882,769	2,882,769	2,882,769	17.0%
Other Production/Granite City					1,590,000	1,590,000	1,590,000	1,590,000	1,590,000	3,319,000	3,319,000	3,319,000	3,319,000	9.6%
Other Production/Inver Hills					920,000	920,000	920,000	920,000	920,000	7,944,000	7,944,000	7,944,000	7,944,000	30.9%
Other Production/Key City					1,590,000	1,590,000	1,590,000	1,590,000	1,590,000	3,319,000	3,319,000	3,319,000	3,319,000	9.6%
Other Production/United Health					-	-	-							
Other Production/United Hospital					-	-	-	-	-	-	-	-	-	
Other Production/West Faribault					1,590,000	1,590,000	1,590,000	1,590,000						
Other Production/Grand Meadow								-	-	17,146,000	17,146,000	17,146,000	17,146,000	
Other Production/Wind Storage									1,590,000	-	-	-	-	
Other Production/Nobles										-	-	-	-	
Hydro Production/Hennepin Island	N/A	N/A	N/A	N/A	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	0.0%
Hydro Production/Lower Dam	N/A	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	
Hydro Production/Upper Dam	N/A	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	
Hydro Production/St. Croix Falls														
Gas Production/6" Pipe														
Gas Production/Maplewood	N/A	N/A	N/A	N/A	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	0.0%
Gas Production/Sibley	N/A	N/A	N/A	N/A	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	0.0%
Gas Production/Wescott	N/A	N/A	N/A	N/A	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	0.0%
Gas Storage/Wescott	N/A	N/A	N/A	N/A	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	0.0%
Gas Production/Grand Forks	N/A		N/A	N/A	2,000	2,000	2,000	2,000	2,000	2,000	2,000			0.0%

Note: Annualized Growth Rates are calculated over the longest possible period for which data is available. For example, the growth rate for Steam Production/Allen King is calculated for the period 1983-2013, while the rate for Steam Production/Sherco Unit 3 is calculated for the period 2005-2013.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Reply Comments

Docket No. **E,G999/CI-13-626**

Dated this 10th day of October 2014

/s/Sharon Ferguson

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