

June 27, 2012

PUBLIC DOCUMENT

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E,G002/D-12-151

Dear Dr. Haar:

Attached are the **PUBLIC Comments** of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Northern States Power Company's (Xcel or the Company), a Minnesota Corporation,
Request for Approval of the Annual Review of Remaining Lives (RL) Depreciation for
Electric and Gas Production and Gas Storage Facilities and Net Salvage Rates for 2012.

The *Petition* was filed on February 17, 2012 by:

Lisa H. Perkett
Director, Capital Asset Accounting
Xcel Energy Services, Inc.
414 Nicollet Mall, 4th Floor
Minneapolis, Minnesota 55401

The Department recommends **limited approval with modification** and is available to answer any questions the Commission may have.

Sincerely,

/s/ NANCY A. CAMPBELL
Financial Analyst

/s/ LERMA LA PLANTE
Financial Analyst

NAC/LL/jl
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. E,G002/D-12-151

I. SUMMARY OF PROPOSAL

On February 17, 2012, Northern States Power Company, d/b/a Xcel Energy (Xcel or the Company), a Minnesota corporation, submitted its annual remaining-life (RL) depreciation review of its electric and gas production and gas storage facilities service lives and net salvage rates (the 2012 Depreciation Study). This submission is required by Minn. Stat. §216B.11 and Minn. Rules parts 7825.0500-7825.0900. The Company also provided a comparison of the proposed electric generation service lives to the planning lives in its Integrated Resource Plan (IRP) as required in the Minnesota Public Utilities Commission's (Commission's) September 8, 2011 *Order* in Docket No. E, G002/D-11-144 (the 2011 Depreciation Study Order).¹

As discussed on pages 3 and 4 of Xcel's depreciation petition, to determine the appropriate remaining lives of these facilities, Xcel "evaluated system demand, availability of fuel supplies, operating and maintenance costs, and future technological advancements that influence the decision to retire electric and natural gas facilities."² Based on its evaluation, the Company proposed that the current remaining lives for all electric and gas production and gas storage facilities be adjusted only for the "passage of time,"³ except for the specific plants discussed below.

¹ 2012 Depreciation Study, Attachments B and F.

² 2012 Depreciation Study, Page 3.

³ The passage-of-time adjustments reduce the remaining lives of all facilities by one year to reflect the passage of time since the last depreciation study. The passage-of-time adjustment does not result in a change of depreciation accrual if the decrease in the remaining life by one year is offset by the increase in accumulated depreciation as a result of the previous year's depreciation accrual. The reduction in both the numerator and the denominator of the remaining life accrual (Plant in service – depreciation reserve/remaining life) results in essentially no increase in the

The Company proposed changes to the remaining lives of the following plants as of January 1, 2012:

A. *Electric Utility*

- Other Production - *Blue Lake Units 1 through 4* remaining lives be lengthened by five years, to six-year remaining lives;
- Other Production - *Granite City Peaking Plant* remaining life be lengthened by five years, to a six-year remaining life; and
- Other Production - *Key City* remaining life be lengthened by five years, to a six-year remaining life;

B. *Gas Utility*

- Wescott LNG Plant-*Compressor Equipment* remaining life be lengthened by 14 years, to a 20-year remaining life.

The Company also proposed one change to the current net salvage rates for the Minnesota Valley steam production plant from (101.9%) to (169.0%). The calculation of the proposed net salvage rate for the Minnesota Valley plant is provided in Attachment G to Xcel's filing. Xcel stated that the change in net salvage value is necessary to recover the costs to demolish and dismantle the facility (including the Minnesota Falls Dam Removal). This proposed change in net salvage rate would increase the annual depreciation expense by \$1.66 million.

Xcel stated that its overall proposal (for all changes listed above) would result in an approximate decrease in depreciation expense of \$477,668 on a total Company basis; this decrease does not include the impact of the decrease in depreciation resulting from the proposed remaining-life changes for the High Bridge and Riverside plants that were reflected in the settlement agreement in Xcel's current electric rate case.⁴ The Commission recently approved the electric rate case settlement agreement.⁵ The impact of the settlement agreement on Xcel's annual depreciation expense is an additional decrease of \$6,393,440 on a total Company basis.

The Company noted that the proposed changes to remaining lives in this filing are the same as the changes to remaining lives in the Settlement Agreement in Xcel's electric rate case (Docket E002/GR-10-971). However, while the proposed remaining lives themselves are the same, the associated dollar impacts are different, as explained on page 11 of the Company's filing.

The Company proposed January 1, 2012 as the effective date of all remaining life changes and net salvage rate changes.

calculated depreciation accrual (e.g., year 1 $(100-0/10 = 10)$, year 2 $(100-10/9 = 10)$). However, if a significant investment has been made, the remaining life should be adjusted to reflect the investment.

⁴ Docket No. E002/GR-10-971.

⁵ Commission Order dated May 14, 2012 (Docket No. E002/GR-10-971) *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*.

II. DOC ANALYSIS

The Minnesota Department of Commerce, Division of Energy Resources' (Department) analysis focuses on the following:

- compliance with the 2011 Depreciation Study Order (as discussed in Section A below);
- Xcel's proposed changes to the remaining lives of electric plant assets (as discussed in Section B below);
- Xcel's proposed changes to the remaining lives of natural gas plant production and gas storage assets (as discussed in Section C below);
- Xcel's proposed changes to the salvage rates of electric and gas plant production and gas storage assets as provided in Attachment B of the instant filing (as discussed in Section D below);
- electric rate case settlements affecting depreciation (as discussed in Section E below); and
- impact of Sherco 3 outage (as discussed in F below).

A. COMPLIANCE WITH 2011 DEPRECIATION ORDERS

1. *Filing Due Dates and Effective Dates*

The 2011 Depreciation Study Order specified that Xcel shall file its next annual remaining life depreciation study of electric and gas production and gas storage facilities by February 17, 2012. Xcel met that deadline.

Xcel satisfied the requirement to review remaining life and salvage factors for its electric and gas production and gas storage facilities and, as discussed below, to compare the service lives in the depreciation study with the integrated resource plan (IRP) planning periods for each electric production facility based upon December 31, 2011 plant and reserve balances.

2. *Comparison of the Electric Generation Remaining Plant Lives in the 2012 Depreciation Study to the Planning Lives in the 2010 Integrated Resource Plan*

In its 2011 Depreciation Study Order, the Commission ordered Xcel to continue to provide, in the 2012 Depreciation Study, an explanation and schedule of the differences between the depreciable service lives and resource planning periods of electric production plant. In compliance with this requirement, Xcel Energy provided a comparison of the lives in the 2012 Depreciation Study to the lives in the 2010 IRP. The Company stated:

We note that the primary difference between the expected operating period in our 2010 IRP and the proposed remaining lives in the filing relate to several peaking facilities. In the 2010 IRP,

we discussed and evaluated potential investments that could extend the remaining lives of those facilities through the end of the 15-year planning period. While we are recommending changes in the lives of some of our peaking plants in this filing, including Granite City and Key City, the proposed improvements needed to extend the lives of these plants out past the end of the 15-year planning period have not been made, and is the primary reason more modest life extensions are being proposed for these plants.

Xcel's Schedule F lists each electric production plant facility, its proposed depreciation life, the IRP planning/modeling end of life, and the rationale for the differences between the depreciation life and the IRP planning life. Based on our review, the Department considers Xcel explanations for the differences between the depreciation life and the IRP planning life to be reasonable at this time. However, to the extent that decisions are made that change the lives of the plants, the effects of those decisions should be included in the next RL filing.

3. Historical Comparison of Changes to Remaining Lives and Net Salvage Rates

In its June 16, 2010 Order in Docket No. E,G002/D-10-173 (2010 Depreciation Study Order), the Commission ordered Xcel to use a new reporting format for the Annual Review of Remaining Lives to include a history of the last time a change occurred to either the estimated life or salvage value estimate. In its 2011 Depreciation Study Order, the Commission continued to require Xcel to include that historical information. In this filing, Xcel provided in Attachment H a historical comparison of changes to remaining lives and net salvage rates. This attachment is a useful reference, providing, for example, the docket numbers in which changes in lives or salvage values occurred, to allow for further background into why such changes occurred.

For example, the last time the net salvage rate for Xcel's Minnesota Valley steam production plant was changed was in Docket E, G002/D-05-288. The Commission's August 26, 2005 Order in that proceeding approved a (101.9%) net salvage rate; in the instant filing, Xcel proposes a net salvage rate of (169.0%).⁶

Overall, the Department concludes that Xcel has complied with Commission's 2011 Depreciation Study Order.

⁶ The Department notes that in a response to a DOC email dated June 19, 2012 (attached) Xcel corrected the proposed net salvage rate from negative 156.5% to negative 169.0% and provided a revised Attachment H to the filing.

B. DEPARTMENT ANALYSIS OF CHANGES TO REMAINING LIVES FOR ELECTRIC PLANT

As stated above, the Company proposed that the current remaining lives for all electric plant be adjusted for the one-year passage of time since the last depreciation study, in addition to the changes in remaining lives of specific plants.

In this petition, Xcel proposed to extend the remaining lives of several of its generating plants. This proposal is of special concern to the Department given Xcel's response to an information request in its most recent rate case (E002/GR-10-971). The Department specifically asked Xcel in Docket No. E002/GR-10-971 in information request 159 whether the Company intended to extend the remaining lives of any of its generating plants within the next two years. Xcel's response identified only the Black Dog and Prairie Island plants as generation facilities with changes in remaining lives. No other generation plant was identified for life extensions. That is, Xcel did not mention any plans to extend the lives of any of the generation facilities for which Xcel now requests an extension.⁷

Based on the above statements, the Department closely examined Xcel's proposed remaining life extensions in this petition. The Department's conclusions are discussed below.

1. Other Production- Blue Lake Units 1 thru 4

Xcel proposed that the remaining life for Blue Lake Units 1 thru 4 be lengthened by five years as of January 1, 2012 from a one-year to a six-year remaining life. That is, the life would extend to December 31, 2017. The estimated financial impact of this change is an annual decrease of \$1.09 million in total Company depreciation expense.⁸

The Department sent DOC Information Request No. 10⁹ (attached) which stated the following:

- a. In Xcel's most recent rate case (Docket E002/GR10-971), the DOC asked Xcel in Information Request 159 the following question: "Is Xcel planning on extending the lives of its generation plants in the next two years? If yes, please identify which generation plant Xcel is planning on extending and the expected life of that extension." DOC notes that Xcel identified Black Dog and Prairie Island as generation with changes in its lives, however, no other generation was identified for life extensions. Please explain why Blue Lake Units 1 through 4 were not identified as generation that would

⁷ Further, the lives of these generation facilities were not extended for ratemaking purposes in Xcel's settlement.

⁸ Based on beginning of year balances (see page 5 of the filing).

⁹ The Department has attached a copy of our information requests and Xcel's responses as referred in these comments as DOC Attachment 1.

have its life extended in the rate case, as now requested in Xcel's February 17, 2012 Annual Remaining Life Depreciation Filing.

- b. In light of the fact that Blue Lake Units 1 thru 4 Peaking Plant only had a one year remaining life, shouldn't Xcel have been able to conclude during the rate case that either the life would need to be extended or the plant be retired in the rate case? Please explain your answer.

The Company's response stated as follows:

- a. Blue Lake was not identified as a generation plant in need of a life extension at the time of our response to Information Request 159 because at that time there was no significant uncertainty surrounding the continued use of small peaking plants like Blue Lake. It was unknown whether the plant would be used past the end of 2012 so it was determined that a life extension of the plant was not prudent.
- b. There are times when the Company will know well in advance about activities which will trigger future remaining life changes. Unfortunately the process of analyzing remaining lives far into the future is not perfect. The rate case Information Request was filed on February 1, 2011, a full year before our 2012 remaining life filing, and two weeks before our 2011 filing was even submitted. While the Information Request response was intended to highlight any known changes which would be made in the future, it was not intended to be a binding statement restricting our opportunity to make more changes if other factors came to light. As we mention in the Information Request, "It is possible through the annual review process for 2012 that additional information could support changes not currently foreseen." Some of the additional information which came to light since our response to Information Request No. 159 includes the fire which disabled Sherco Unit 3 and delay of the proposed new unit at the Black Dog plant. With the loss of production of Sherco and the delay of expected future production at Black Dog it was determined that small peaking plants like Blue Lake may be important as a continued production asset to ensure system reliability for customers.

The Department has three concerns with Xcel's justification for the proposed Blue Lake life extension. First, the Department is concerned that Xcel indicated in their response to the Department's information request in the most recent rate case that the Company planned only to extend the lives of its Black Dog and Prairie Island plants in the next two years, but then proposed to extend the life of Blue Lake Units 1 through 4 and other generation facilities in this depreciation petition. This practice results in higher depreciation expense being collected through rates determined in the rate case, but lower depreciation expense recorded for accounting purposes, which can result in an over recovery of costs. The potential for over recovery for Blue Lake is a very real possibility, because at the end of 2012 Xcel would have fully collected the costs of this facility in its rates and for accounting purposes. If Xcel is allowed to spread the collection of the final year's depreciation expense over the next five years, the Company will likely include Blue Lake in their next rate case (expected to be filed later this year). The Department raised a similar issue about decreasing depreciation rates right after a rate case in Xcel's 2010 remaining life depreciation study regarding Sherco 3. Although an adjustment was not required at that time, the Company was clearly put on notice about this concern in that proceeding.

Second, the Department notes that generally capital additions are the main reason for increasing the life of an asset or plant; however, Xcel has not provided support for any capital additions for the Blue Lake Units 1 through 4 that support the life extension proposed by Xcel in this petition. The Department notes that lack of capital additions and concerns with rate recovery in rate cases compared to depreciation filings were some of the same concerns raised by the Department in its comments dated September 29, 2011 in Interstate Power and Light's (IPL) 2011 Annual Depreciation Study in Docket No. E,G002/D-11-143. As a result of the Department's concerns in IPL's 2011 Annual Depreciation Study, the Commission in its February 15, 2012 Order, denied IPL's request to extend several of the depreciation lives due to lack of capital additions or inconsistency with recovery approved in IPL's rate case.

Third, the justification Xcel provided in its response to Information Request No. 10 is flawed. Xcel indicated that with the loss of production of Sherco 3 due to a fire and the delay of the proposed new unit at Black Dog, small peaking plants like Blue Lake are needed to ensure system reliability for customers. However, the Department notes that the Sherco 3 and Black Dog units are considered baseload units, while Blue Lake Units 1 through 4 are old peaking units; therefore, these are not interchangeable units for energy production purposes since baseload and peaking units serve different functions.

In addition, on May 30, 2012 the Office of Administrative Hearings (OAH) issued an order granting the petition of the Company to withdraw its application for a Certificate of Need (CN) for the Black Dog generating plant repowering project.¹⁰ Xcel withdrew its application because Xcel has concluded that, based on the Company's updated IRP¹¹ Xcel's proposed Black Dog

¹⁰ Docket No. E002/CN-11-187- *In the Matter of the Petition of Northern States Power Company for the Black Dog Generating Plant Repowering Project.*

¹¹ Filed December 1, 2011 in Docket No. E002/RP-10-825.

project is no longer needed. In other words, it was Xcel's choice to withdraw the Black Dog CN application as a result of Xcel's assessment that the unit was not needed. However, in this current depreciation filing, Xcel asserts that older almost fully depreciated peaker units are needed and must continue to operate. Xcel's contradictory statements will need to be sorted out when Xcel's request to withdraw the Black Dog CN comes before the Commission; for now the question in this proceeding is whether it is appropriate to extend the remaining lives of the facilities. The Department notes that the remaining life established for accounting purposes does not limit Xcel's ability to operate a plant that is nearly or fully depreciated. That is, just because Xcel has recovered the costs of a generation plant for ratemaking and accounting purposes, Xcel does not need to stop operating this plant if the plant continues to be useful and needed. The Department concludes that Xcel's assertions that energy needs due to situations concerning Sherco 3 and Black Dog support a proposed life extension for Blue Lake are flawed.

Therefore, the Department concludes that it is not reasonable to extend the lives of Blue Lake Units 1 through 4 from one year to six years, or to reduce the annual depreciation expense by \$1.09 million on a total Company basis (approximately \$809,036 for the Minnesota Jurisdiction using the plant allocator of 74.2235 percent as approved in Xcel's most recent rate case.) The Department recommends that the Commission deny Xcel's request to extend the remaining life of the Blue Lake Units 1 to 4 for the following reasons:

- there are no plant additions to support such a life extension;
- granting the life extension would increase the potential for over recovery since, as of the end of 2012, Xcel will have fully recovered in rates the costs of Blue Lake Units 1 to 4; and
- denying the life extension would not prevent the operation of these units for reliability purposes.

2. *Other Production - Granite City*

The Company proposed to extend the remaining life of the Granite City peaking plant from one year to six years as of January 1, 2012. The estimated impact to total Company depreciation expense for this proposed change is an annual decrease of \$850,000.¹²

Xcel indicated in its response to Information Request No. 8 that, with the loss of production at Sherco 3 and the delay of expected production at Black Dog, small peaking plants like Granite City are needed. The Department notes the same concerns with the proposed Granite City life extension as were discussed above for Blue Lake Units 1 through 4. Further, the Department notes that Xcel's December 1, 2011 "Resource Plan Update" in Docket No. E002/RP-10-825 indicates that the Company plans to retire the Granite City plant in 2013.¹³ This update was filed after the Sherco 3 incident and also indicated Xcel's intent to withdraw the Black Dog CN.

¹² Based on beginning of year balances (see page 5 of the filing).

¹³ See page Attachment A, page 1 of 2 of Xcel's "Resource Plan Update."

Based on the arguments discussed above, the Department concludes that it is not reasonable to extend the life of the Granite City peaking plant from one year to six years as of January 1, 2012, or to reduce annual depreciation expense by \$850,000 on a total Company basis (approximately \$630,900 for the Minnesota Jurisdiction using the plant allocator of 74.2235 percent as approved in Xcel's most recent rate case.) Therefore, the Department recommends that the Commission deny Xcel's request to extend the remaining life of the Granite City peaking plant.

3. Other Production - Key City

The Company proposed to extend the remaining life of Key City peaking plant from one year to six years as of January 1, 2012. The estimated impact of this change to total Company depreciation expense is an annual decrease of \$450,000.¹⁴

Xcel indicated in its response to DOC Information Request No. 11 that, with the loss of production at Sherco 3 and the delay of expected production at Black Dog, small peaking plants like Key City are needed. The Department notes the same concerns with the Key City life extension as were discussed above for Blue Lake Units 1 through 4. Further, the Department notes that Xcel's December 1, 2011 "Resource Plan Update" in Docket No. E002/RP-10-825 indicates that the Company plans to retire the Key City plant in 2013.¹⁵

Based on the arguments discussed above, the Department concludes that it is not reasonable to extend the life of the Key City peaking plant from one year to six years as of January 1, 2012, or reduce annual depreciation expense by \$450,000 on a total Company basis (approximately \$334,006 for the Minnesota Jurisdiction using the plant allocator of 74.2235 percent as approved in Xcel's most recent rate case.) Therefore, the Department recommends that the Commission deny Xcel's request to extend the remaining life of the Key City peaking plant.

C. DEPARTMENT ANALYSIS OF CHANGES TO REMAINING LIVES FOR GAS PRODUCTION AND GAS STORAGE

As stated above, the Company proposed that the current remaining lives for all gas production and gas storage facilities be adjusted for the one-year passage of time since the last depreciation study in addition to extending the remaining life of the compressor equipment at the Wescott gas storage plant as discussed below.

1. Gas Storage Wescott Compressor Equipment

The Wescott LNG Plant is a liquefied natural gas plant placed in service in 1972. The plant cools, then stores, the liquefied natural gas (LNG) in large storage tanks. Vaporizing equipment is used later to warm and convert the liquefied methane back to gas for use in the distribution system. In past years, the remaining life used for the structures and improvements account for

¹⁴ Based on beginning of year balances (see page 6 of the filing).

¹⁵ See Attachment A, page 1 of 2, in Xcel's "Resource Plan Update."

both the Wescott Production Plant and the Wescott LNG Plant has been the same since these facilities would likely be retired from service simultaneously. However, as stated by the Company, the Wescott LNG Plant is unique in that there are separate identifiable systems within the plant that function independently from other systems, thereby allowing for the possibility of assigning a different remaining life for each system. Hence, the life used for the structure and improvement account does not necessarily need to match the life of other equipment.

Presently all systems have a remaining life of 6 years, as of January 1, 2012, except for the vaporizing equipment. The vaporizing equipment currently has a remaining life of 16 years. The Company stated that it is currently in the process of replacing the refrigerated compressor unit at the Wescott LNG Plant. The project is expected to be completed sometime in the second quarter of 2012. The forecasted capitalized value of this replacement is approximately \$14.5 million. Due to the upgrade and replacement of the refrigerated compressor unit, Xcel proposed to increase the remaining life for the compressor equipment account from 6 years to 20 years effective January 1, 2012.

The Department notes that in Docket E002/PA-11-902 the Company had submitted a replacement options cost-benefit analysis in response to DOC Information Request No. 2. Xcel considered three options for replacing the refrigerated compressor unit:

- Replace the unit with a more efficient gas turbine-driven compressor;
- Replace the unit with an electric-driven compressor; or
- Discontinue using the Wescott LNG Plant.

The Company's analysis indicated that replacing the unit with a gas turbine-driven compressor was the most cost-effective solution. The estimated cost of that option at that time was \$12.76 million while Xcel stated in the instant petition that the estimated cost of replacing the unit is \$14.5 million. The Company's explanation for the difference was that there are additional costs of auxiliary projects and AFUDC (Allowance for Funds Used During Construction) which were not included in the cost benefit analysis shown in the Company's response to Information Request No. 2 in Docket E002/PA-11-902. The Department notes that if the cost of auxiliary projects and AFUDC is added to the option of replacing the next most cost-effective option (replacing the unit with an electric-driven compressor), this would result in a much higher total cost than Xcel's proposal. Thus, the Department concludes that the \$14.5 million replacement cost of the refrigerated compressor unit at the Wescott LNG Plant appears to be reasonable.

The Department recommends the Commission approve the Company's request to increasing the remaining life of the Gas Storage Westcott Compressor Equipment account from 6 years to 20 years.

D. CHANGES IN NET SALVAGE RATES

Xcel provided as Attachment B to its filing a summary of all present and proposed net salvage rates. The Company's calculation of the proposed net salvage rate for the Minnesota Valley Plant is provided as Attachment G to this filing. The Company proposed one change – a decrease to the net salvage rate for the Minnesota Valley steam production plant from (101.9%) to (169.0%), which includes the Minnesota Falls Dam removal project discussed below. This proposed change in net salvage rate would increase the annual depreciation expense by \$1.66 million.

1. Demolition, Decommissioning and Abatement at Minnesota Valley

The Minnesota Valley Plant is no longer in operation but still being depreciated in order to collect the cost of decommissioning as initially approved by the Commission on August 26, 2005 in Docket E,G002/D-05-288. The Commission approved a remaining life of 12.5 years and a (70%) net salvage value. In Docket No. E, G002/D-10-173, the Company submitted a 2009 Demolition study of the Minnesota Valley Plant and proposed a (101.9%) net salvage rate, which was approved by the Commission on June 16, 2010.

The Company stated that the 2009 estimate of \$13,874,964 for the demolition and dismantlement of the Minnesota Valley Plant was provided by TLG Services, Inc. The Company noted that, as a result of its recent experience with abatement, demolition, and decommissioning activities at the Riverside and High Bridge Plants, the Company has gained a better understanding of the scope of work required for these activities. As a result, in 2011, Xcel requested new budgetary quotes from four outside contractors to perform the demolition, remediation and decommissioning work at the Minnesota Valley Plant. The new estimate as presented by the Company on page 8 of the instant filing showed the following.

	Current Estimate
Asbestos abatement	\$ 4,500,000
Demolition w/ scrap credit	3,081,000
Site work	750,000
Oversight and Administrative	2,544,000
Contingency	2,651,000
Escalation	2,476,000
Coal yard closure	1,875,000
Hazardous material abatement	880,000
Total	\$ 18,757,000

The Company also noted that it has completed the ash pond closure at the Minnesota Valley Plant, as well as a portion of the asbestos abatement. According to Xcel, the costs for these activities were approximately \$2.6 million and \$900,000 respectively. The Company noted in its filing that these costs are not included in the estimate above, as the estimate reflects costs to complete demolition, decommissioning and abatement going forward.

The Department asked the Company in Information Request No. 3 (attached) the following:

- Please provide copies of quotes from the four contractors and fully explain how they compare to the total estimate;
- Please explain how contractor will be selected; and
- Please provide schedule for when work will occur and be completed.

The Company's response showed contractor quotes for three scopes of work: asbestos abatement, demolition with scrap credit, and site work. The remaining five scopes of work - oversight and administrative, contingency, escalation, coal yard closure and hazardous material abatement - were estimates of the Company. Based on our review of the contractor quotes provided by the Company, the Department considers the quotes for asbestos abatement, demolition with scrap credit, and site work, to be reasonable estimates.

The Department also reviewed the remaining estimates provided by the Company and as discussed in the Company's response to DOC Information Request No. 3. Based on our review, the Department notes that the contingency cost category estimate of \$2,651,000, and the escalation cost category estimate of \$2,476,000 together comprise 27 percent of the total estimate of \$18,757,000, which is quite high. The Company provided the following explanation for the escalation and contingency cost categories:

The escalation component is based upon the overall project schedule developed from the duration of time presented in the contractors' proposals and clarifications. The proposals and internally developed estimates are in 2011 dollars.

It is normal business practice to include contingencies in capital project estimates. Contingency costs are intended to account for unplanned or uncertain costs that arise during the construction process. The Company typically assigns a particular percentage to project costs estimates in order to arrive at a contingency figure. We used the same process for the contingency component of the decommissioning, remediation and demolition at Minnesota Valley.

The Department does not believe that the Company's explanation above provides sufficient support for the escalation and contingency cost categories to comprise 27 percent of the total cost

estimate for Minnesota Valley Plant decommissioning. Therefore, the Department requests that the Company provide additional information in its reply comments to support these cost estimates.

2. Minnesota Falls Dam Removal

Xcel stated that in addition to the demolition, remediation and decommissioning of Minnesota Valley Plant facilities, the Company must also remove the Minnesota Falls Dam. Inspections were performed by Barr Engineering Company and the Minnesota Department of Natural Resources (MNDR) Dam Safety staff, which identified several potential structural deficiencies within the aging structure. As a result of the dam's deficiencies, the MNDR required the Company to develop a long-term plan to remove, repair or otherwise modify the dam to ensure its safe operation. The Company stated that removal of the dam was determined to be the most cost-effective option to address the deficiencies. The Company currently plans to remove the dam during the summer of 2012. The Company estimated the removal of the dam at approximately **[TRADE SECRET DATA HAS BEEN EXCISED]**.

The Department sent DOC Information Request No. 9 (attached) requesting information regarding the estimates that Xcel received from the engineering consultant and three contractors for the dam removal and demolition.

The Company replied as follows:

We note that since our remaining lives petition was submitted we have received an offer from an entity to take ownership of the dam. As part of the proposal, the Company would pay the entity approximately **[TRADE SECRET DATA HAS BEEN EXCISED]** and the entity would undertake ongoing responsibility for the long-term plan to remove, repair or otherwise modify the dam to ensure its safe operation. We have accepted this proposal, it will be less costly than if the Company were to remove the dam. However, an agreement must still be finalized. When we file reply comments we intend to provide an update to our remaining live petition to reflect the status of this new development, as well as the corresponding change to our depreciation expense. Please let us know if you believe there is a better procedural course of action.

Based on our review, the Department recommends that the Company in its reply comments provide an update on the status of the sale of the Minnesota Falls Dam. Additionally, in reply comments Xcel should provide the updated net salvage rate for the Minnesota Valley Plant and the corresponding change in depreciation expense to reflect the sale of the Minnesota Falls Dam.

E. ELECTRIC RATE CASE SETTLEMENT RELATED TO REMAINING LIFE EXTENSION OF RIVERSIDE AND HIGH BRIDGE GENERATION PLANTS

In its May 14, 2012 Order in Docket No. E002/GR-10-971, the Commission approved the settlement agreement submitted by the Company in the electric rate case. Part of the settlement agreement included adjustments to decrease the depreciation expense because of the extensions in the remaining lives of the Riverside and High Bridge power plants.

In the settlement agreement, the Company lengthened the remaining lives of both the Riverside and High Bridge power plants by 10 years each, which resulted in a decrease in annual depreciation expenses of \$4.5 million for Xcel's Minnesota jurisdiction. Specifically, the Riverside Plant's remaining life was extended from 27.2 years to 37.2 years as of January 1, 2012, resulting in a total Company decrease in depreciation expense of \$2.63 million. The High Bridge Plant's remaining life was extended from 26.4 years to 36.4 years as of January 1, 2012, resulting in a total Company decrease in depreciation expense of \$3.76 million.

According to Xcel's 2012 Depreciation Study, an extension of the remaining lives of the Riverside and High Bridge power plants by 10 years would decrease annual depreciation expense by \$6.39 million on a total-Company basis. The Company stated that these numbers differ from the change in depreciation stated in the rate case settlement agreement, since the numbers presented in the instant petition were based on actual plant and reserve balances as of January 1, 2012, and depreciation numbers are presented on a total-Company basis.

The Department asked Xcel in DOC Information Request No. 4 to provide documentation (like manufacturer's warranty and any other information) to support the Company's proposal to extend the remaining lives of the High Bridge and Riverside Plants to 36.4 years and 37.2 years, respectively.

The Company responded as follows:

Generally, the Company reviews the remaining life of a generating plant based on existing investments; proposes life extensions as the time approaches to make the additional investments that will support continued operation beyond the current remaining life. However, for both the High Bridge and Riverside Plants, based on industry standards, it can be expected that, with additional investment, these two plants will continue operation for 40 years. In addition, it can also be expected that, when needed, the Company will make the additional investment. These two reasonable assumptions support lengthening the remaining lives of these plants by 10 years.

Our analysis did not include review of documents such as manufacturer's warranty and we do not have any such documents in support of our request. However, the US Energy Information Administration published in Today in Energy on June 16, 2011, charts presenting data on the age and capacity of existing electric generators by fuel type as of the end of 2010. This information shows that across the industry a significant number of existing gas generation facilities between 30 and 50 years old continued to be in operation at the end of 2010. Therefore, we believe that, with additional investment as required, the relatively newer High Bridge and Riverside Plants should be able to operate at least as long as 30 to 50 years old gas plants in operation today. DOC IR-04, Attachment 1 contains a copy of this article.

The Department was disappointed that Xcel was unable to provide any manufacturer's warranty or information specific to Xcel's High Bridge and Riverside Plants. However, the Department did find the "Today in Energy" article and chart to be helpful in supporting a 30 to 50 year life expectancy for natural gas-fired electric generating units. As a result, the Department concludes that extending the lives of both the Riverside and High Bridge Power Plants for 10 years is reasonable. The Department, however, requests that Xcel provide more support for its transmission and distribution average service life extensions in its July 2012 filing.

The Department asked Xcel in DOC Information Request No. 1 to reconcile the overall impact of the decrease of \$6.39 million (total Company) in depreciation expense as provided in the 2012 Depreciation Study, with the \$4.5 million (Minnesota jurisdiction) decrease in revenue requirement resulting from the settlement agreement approved in the Company's most recent electric rate case (Docket No. E002/GR-10-971).

Xcel responded as follows:

The calculation of the impact of the changes in this remaining life filing is fundamentally different from the revenue requirement that was shown as a part of the Settlement Agreement in the electric rate case. The numbers presented in this filing are based on actual plant and reserve balances as of January 1, 2012, and depreciation numbers are presented for the total Company. The numbers presented in the Settlement Agreement are based on the 2011 test year data that was completed in 2010 for the State of Minnesota jurisdiction.

The \$4.5 million decrease in Minnesota jurisdictional revenue requirements identified in the Settlement Agreement is the 2011 revenue requirement impact of the change in lives for our High

Bridge and Riverside plants. Our Remaining Life filing identifies a \$6.4 million decrease in total NSPM 2012 depreciation expense for these same two plants. The revenue requirements impact included in the Settlement Agreement reflects the full impact of the change in depreciation rates (depreciation expense as well as return on rate base) while the change in depreciation shown in the Remaining Life filing is the depreciation expense impact only, for the total Company.

The \$4.5 million decrease in Minnesota jurisdictional revenue requirements for our High Bridge and Riverside plants was calculated base on an estimated total NSPM change in 2011 depreciation expense of \$6,304,192.

Based on our review, the Department confirms that the Company has reconciled its calculation for the annual decrease of depreciation expense established in the settlement agreement with the decrease proposed in the instant docket resulting from the remaining lives extension for the Riverside and High Bridge Power Plants.

F. SHERCO 3

The Company noted that on November 19, 2011, Unit 3 of the Sherco steam production plant experienced failure during testing while returning to service following a scheduled maintenance overhaul that began in September 2011. The Company stated that at the time of the failure, several major projects totaling approximately \$23 million had been completed during the scheduled overhaul. The Company stated that it has placed the costs associated with these projects into a Held for Future Use account (FERC Account 105, Electric plant held for future use). While in Held for Future Use account the projects will be included in rate base but will not be depreciated. Once Sherco Unit 3 is back in service, the project will begin depreciation using the approved remaining life for Sherco 3 at the time.

The Department asked Xcel in DOC Information Request No. 5 to provide a break out of the approximately \$23 million in costs of the major projects completed for Sherco, to identify which unit each project relates to (unit 1, 2 or 3). The Company replied that all of the \$23 million relates to Sherco Unit 3.¹⁶ The amount reflects installation of equipment to replace various Sherco Unit 3 turbine sections with a more efficient design and to increase steam flow allowing a 20- to 40-megawatt (MW) increase of rating capacity.

¹⁶ By email, the Department asked Xcel if the entire Sherco 3 unit (not just the \$23 million in improvements) was transferred to FERC Account 105, Electric plant held for future use, and as result was no longer being depreciated. Xcel noted that the Sherco 3 unit was not transferred to FERC Account 105, but continues to be recorded in Account 101, Electric plant in-service and continues to be depreciated.

The Department further asked the Company, in DOC Information Request No. 5, to explain why Xcel's proposed accounting and ratemaking, described on page 11 of Xcel's depreciation filing, is reasonable and meets the criteria of Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, especially Account 105, Electric plant held for future use, and is consistent with the Commission's past practice of dealing with plant held for future use.

The Company responded as follows:

Xcel Energy's major projects included within FERC Account 105, Electric Plant Held for Future Use, are specific to Sherco Unit 3 and were completed in November 2011. Due to the significant failure at Sherco Unit 3 in November 2011, these projects are not currently in use and will not be in use until the unit returns to operations at which point these projects will be operational. Since these assets have not been used, depreciating the asset before their initial use would not be appropriate. Also FERC rules state that this account shall be used for the original cost of electric plant owned and held for future use under a definitive plan by the company. Since Xcel Energy has not used these assets in electric generation and has a definitive plan to use them once Sherco 3 returns to operations, the accounting treatment is deemed reasonable.

Finally, the Department asked Xcel, in DOC Information Request No. 5, what the Company's plans are for Sherco 3 that supports inclusion of the \$23 million in FERC Account 105, Electric plant held for future use.

Xcel responded as follows:

Xcel Energy is currently repairing Sherco Unit 3 for the damage performed by the failure and intends to resume operations as soon as the unit is deemed to be safe and fully operational. At that time, the assets currently held in FERC Account 105 will be placed into service and depreciated over the remaining life. At this time Xcel Energy is unable to definitively state when Sherco Unit 3 is expected to return to operations.

The Company stated in its response above that the major projects for Sherco 3 were completed in November 2011. The Department requests that Xcel provide in its reply comments information to show that these major project additions (of approximately \$23 million) for Sherco 3 were included and approved in current rates for the 2011 test year, and what proportion of these costs were included as a plant addition to rate base and related depreciation expense.

III. RECOMMENDATIONS

The Department recommends that the Commission:

- approve Xcel's proposed service lives, salvage rates, and resulting depreciation rates effective January 1, 2012 for plant in service, except for those related to Blue Lake Units 1 thru 4, Granite City, Key City, Minnesota Valley and Sherco 3;
- deny Xcel's request to extend the life of Blue Lake Units 1 through 4 from one year to six years as of January 1, 2012;
- deny Xcel's request to extend the life of the Granite City Peaking Plant from one year to six years as of January 1, 2012;
- deny Xcel's request to extend the life of the Key City Peaking Plant from one year to six years as of January 1, 2012;
- require Xcel to continue to provide in future depreciation studies an explanation and schedule of the differences between the depreciation remaining lives and IRP planning lives of electric production plant;
- require Xcel to continue to provide in future depreciation studies a historical comparison of changes in remaining lives and net salvage rates;
- require Xcel to file its next annual remaining lives update for electric and gas production and gas storage facilities on February 18, 2013; and
- require Xcel to file its next five-year depreciation study and net salvage rate study for electric and gas production and gas storage facilities on February 17, 2015.

Further, the Department requests that Xcel provide the following in Reply Comments:

- further explanation to support the escalation and contingency cost categories comprising 27 percent of the total decommissioning cost estimate for the Minnesota Valley Plant;
- an update on the status of the sale of the Minnesota Falls Dam, including the updated net salvage rate for the Minnesota Valley Plant and the corresponding change in depreciation expense to reflect the sale of Minnesota Falls Dam; and

- confirmation that the major project additions for Sherco 3 were included in current rates for the 2011 test year, and the proportion included as a plant addition to rate base and related depreciation expense;

Finally, the Department requests that Xcel provide sufficient support for its transmission and distribution average service life extensions in its July 2012 filing.

/jl

DOC Attachment 1

- ☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante

Department of Commerce
E-Mail Request

Date Received: June 19, 2012

Question:

Subject: Minnesota Valley Net Salvage Rate

Reference: Depreciation Filing, Page 10, Attachment H, Page 1 of 9

During our analysis of Xcel 2012 Depreciation filing, we found these conflicting figures/data in the filing for the proposed net salvage rate of Minnesota Valley plant.

a.) On Page 10 - the proposed Net salvage rate as of 01/01/2012 - (169%)

b.) On Schedule H page 1 of 9 - the proposed Net salvage rate - (156.5%)

Please show us where we can find in the filing the reconciliation of these data or let us know if there was an error or omission.

Response:

The correct net salvage rate for Minnesota Valley is a negative 169.0%. The net salvage rate of negative 156.5% currently shown on Attachment H, page 1 of 9, is an error and the Attachment did not get updated to reflect the "final" net salvage rate of negative 169.0%. Attachment G in the filing shows the comparison between the present net salvage rate of negative 101.9% and the proposed net salvage rate of negative 169.0%. The proposed net salvage rate of negative 169.0% is the result of dividing the proposed cost of removal for Minnesota Valley of \$23,000,000 by the Minnesota Valley plant balance at 1/1/2011 of \$13,611,631. A revised Attachment H, with a corrected page 1, has been attached to this response.

Response By: Lisa Perkett

Title: Director

Department: Capital Asset Accounting

Telephone: 612-330-6950

Date: June 20, 2012

Xcel Energy
Historical Comparison of Changes to Remaining Lives
Electric Steam Production

Account	Description	Current Approved Remaining Life 01/01/11 (Yrs)	Proposed Remaining Life 01/01/12 (Yrs)	Current Approved Net Salvage 01/01/11 (%)	Proposed Net Salvage 01/01/12 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
BlackDog											
E311	Structures & Improvements	21.0	20.0	-8.3	-8.3	EG002-D-99-173	4.9	EG002-D-10-173	21.7	0	1
E312	Boiler Plant Equipment	5.0	4.0	-18.0	-18.0	EG002-D-11-144	3.0	EG002-D-10-173	-18.0	1	1
E314	Turbogenerator Units	5.0	4.0	-18.0	-18.0	EG002-D-11-144	3.0	EG002-D-10-173	-18.0	1	1
E315	Accessory Electric Equipment	5.0	4.0	-18.0	-18.0	EG002-D-11-144	3.0	EG002-D-10-173	-18.0	1	1
E316	Miscellaneous Power Plant Equipment	5.0	4.0	-18.0	-18.0	EG002-D-11-144	3.0	EG002-D-10-173	-18.0	1	1
Allen S. King											
E311	Structures & Improvements	26.5	25.5	-5.5	-5.5	EG002-D-07-251	23.5	EG002-D-10-173	34.5	1	1
E312	Boiler Plant Equipment	26.5	25.5	-5.5	-5.5	EG002-D-07-251	23.5	EG002-D-10-173	-5.5	1	1
E314	Turbogenerator Units	26.5	25.5	-5.5	-5.5	EG002-D-07-251	23.5	EG002-D-10-173	-5.5	1	1
E315	Accessory Electric Equipment	26.5	25.5	-5.5	-5.5	EG002-D-07-251	23.5	EG002-D-10-173	-5.5	1	1
E316	Miscellaneous Power Plant Equipment	26.5	25.5	-5.5	-5.5	EG002-D-07-251	23.5	EG002-D-10-173	-5.5	1	1
Minnesota Valley											
E311	Structures & Improvements	6.5	5.5	-101.9	-169.0	EG002-D-05-288	12.5	EG002-D-10-173	-31.9	0	1
E312	Boiler Plant Equipment	6.5	5.5	-101.9	-169.0	EG002-D-05-288	12.5	EG002-D-10-173	-31.9	0	1
E314	Turbogenerator Units	6.5	5.5	-101.9	-169.0	EG002-D-05-288	12.5	EG002-D-10-173	-31.9	0	1
E315	Accessory Electric Equipment	6.5	5.5	-101.9	-169.0	EG002-D-05-288	12.5	EG002-D-10-173	-31.9	0	1
E316	Miscellaneous Power Plant Equipment	6.5	5.5	-101.9	-169.0	EG002-D-05-288	12.5	EG002-D-10-173	-31.9	0	1
Red Wing											
E311	Structures & Improvements	7.0	6.0	-23.3	-23.3	EG002-D-10-173	5.0	EG002-D-10-173	11.7	2	1
E312	Boiler Plant Equipment	7.0	6.0	-23.3	-23.3	EG002-D-10-173	5.0	EG002-D-10-173	-23.3	2	1
E314	Turbogenerator Units	7.0	6.0	-23.3	-23.3	EG002-D-10-173	5.0	EG002-D-10-173	-23.3	2	1
E315	Accessory Electric Equipment	7.0	6.0	-23.3	-23.3	EG002-D-10-173	5.0	EG002-D-10-173	-23.3	2	1
E316	Miscellaneous Power Plant Equipment	7.0	6.0	-23.3	-23.3	EG002-D-10-173	5.0	EG002-D-10-173	-23.3	2	1

Account	Description	Current Approved Remaining Life 01/01/11 (Yrs)	Proposed Remaining Life 01/01/12 (Yrs)	Current Approved Net Salvage 01/01/11 (%)	Proposed Net Salvage 01/01/12 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Sheeted Unit 1 & 2											
E311	Structures & Improvements	12.0	11.0	-5.1	-5.1	EG002-D-08-189	3.0	EG002-D-10-173	24.9	1	1
E312	Boiler Plant Equipment	12.0	11.0	-5.1	-5.1	EG002-D-08-189	3.0	EG002-D-10-173	-5.1	1	1
E314	Turbogenerator Units	12.0	11.0	-5.1	-5.1	EG002-D-08-189	3.0	EG002-D-10-173	-5.1	1	1
E315	Accessory Electric Equipment	12.0	11.0	-5.1	-5.1	EG002-D-08-189	3.0	EG002-D-10-173	-5.1	1	1
E316	Miscellaneous Power Plant Equipment	12.0	11.0	-5.1	-5.1	EG002-D-08-189	3.0	EG002-D-10-173	-5.1	1	1
Sheeted Unit 3											
E311	Structures & Improvements	22.0	21.0	-4.3	-4.3	EG002-D-10-173	10.0	EG002-D-10-173	15.7	2	1
E312	Boiler Plant Equipment	22.0	21.0	-4.3	-4.3	EG002-D-10-173	10.0	EG002-D-10-173	-4.3	2	1
E314	Turbogenerator Units	22.0	21.0	-4.3	-4.3	EG002-D-10-173	10.0	EG002-D-10-173	-4.3	2	1
E315	Accessory Electric Equipment	22.0	21.0	-4.3	-4.3	EG002-D-10-173	10.0	EG002-D-10-173	-4.3	2	1
E316	Miscellaneous Power Plant Equipment	22.0	21.0	-4.3	-4.3	EG002-D-10-173	10.0	EG002-D-10-173	-4.3	2	1
Winmarth											
E311	Structures & Improvements	7.0	6.0	-23.0	-23.0	EG002-D-10-173	5.0	EG002-D-10-173	12.0	2	1
E312	Boiler Plant Equipment	7.0	6.0	-23.0	-23.0	EG002-D-10-173	5.0	EG002-D-10-173	-23.0	2	1
E314	Turbogenerator Units	7.0	6.0	-23.0	-23.0	EG002-D-10-173	5.0	EG002-D-10-173	-23.0	2	1
E315	Accessory Electric Equipment	7.0	6.0	-23.0	-23.0	EG002-D-10-173	5.0	EG002-D-10-173	-23.0	2	1
E316	Miscellaneous Power Plant Equipment	7.0	6.0	-23.0	-23.0	EG002-D-10-173	5.0	EG002-D-10-173	-23.0	2	1

Xcel Energy
Historical Comparison of Changes to Remaining Lives
Electric Nuclear Production

Account	Description	Current Approved Remaining Life 01/01/11 (Yrs)	Proposed Remaining Life 01/01/12 (Yrs)	Current Approved Net Salvage 01/01/11 (%)	Proposed Net Salvage 01/01/12 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Monticello											
E302	Franchises & Consents	19.8	18.8	0.0	0.0	EG002-D-07-251	20.0	N/A	N/A	1	N/A
E321	Structures & Improvements	19.8	18.8	0.0	0.0	EG002-D-07-251	20.0	N/A	N/A	1	N/A
E322	Reactor Plant Equipment	19.8	18.8	0.0	0.0	EG002-D-07-251	20.0	N/A	N/A	1	N/A
E323	Turbogenerator Units	19.8	18.8	0.0	0.0	EG002-D-07-251	20.0	N/A	N/A	1	N/A
E324	Accessory Electric Equipment	19.8	18.8	0.0	0.0	EG002-D-07-251	20.0	N/A	N/A	1	N/A
E325	Miscellaneous Power Plant Equipment	19.8	18.8	0.0	0.0	EG002-D-07-251	20.0	N/A	N/A	1	N/A
Monticello - Interim Storage Facility											
E321	Structures and Improvements	19.8	18.8	0.0	0.0	EG002-D-07-251	20.0	N/A	N/A	1	N/A
E322	Reactor Plant Equipment	19.8	18.8	0.0	0.0	EG002-D-07-251	20.0	N/A	N/A	1	N/A
Prairie Island											
E321	Structures & Improvements	23.3	22.3	0.0	0.0	EG002-D-11-144	10.0	N/A	N/A	2	N/A
E322	Reactor Plant Equipment	23.3	22.3	0.0	0.0	EG002-D-11-144	10.0	N/A	N/A	2	N/A
E323	Turbogenerator Units	23.3	22.3	0.0	0.0	EG002-D-11-144	10.0	N/A	N/A	2	N/A
E324	Accessory Electric Equipment	23.3	22.3	0.0	0.0	EG002-D-11-144	10.0	N/A	N/A	2	N/A
E325	Miscellaneous Power Plant Equipment	23.3	22.3	0.0	0.0	EG002-D-11-144	10.0	N/A	N/A	2	N/A
Prairie Island - Interim Storage Facility											
E321	Structures and Improvements	23.3	22.3	0.0	0.0	EG002-D-11-144	10.0	N/A	N/A	2	N/A
E322	Reactor Plant Equipment	23.3	22.3	0.0	0.0	EG002-D-11-144	10.0	N/A	N/A	2	N/A

Xcel Energy
Historical Comparison of Changes to Remaining Lives
Electric Hydro Production

Account	Description	Current Approved Remaining Life 01/01/11 (Yrs)	Proposed Remaining Life 01/01/12 (Yrs)	Current Approved Net Salvage 01/01/11 (%)	Proposed Net Salvage 01/01/12 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
E302	Franchises & Consents	23.2	22.2	0.0	0.0	EG002-D-05-288	2.2	EG002-D-05-288	N/A	0	N/A
E331	Structures & Improvements	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-20.0	0	0
E332	Reservoirs, Dams & Waterways	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-15.0	0	0
E333	Water Wheels, Turbines & Generators	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-35.0	0	0
E334	Accessory Electric Equipment	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-35.0	0	0
E335	Miscellaneous Power Plant Equipment	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-35.0	0	0
Lower Dam											
E331	Structures & Improvements	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-20.0	0	0
E332	Reservoirs, Dams & Waterways	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-15.0	0	0
Upper Dam											
E332	Reservoirs, Dams & Waterways	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-15.0	0	0
E335	Miscellaneous Power Plant Equipment	23.2	22.2	-30.0	-30.0	EG002-D-05-288	2.2	EG002-D-05-288	-35.0	0	0

Electric Other Production

Account	Description	Current Approved Remaining Life 01/01/11 (Yrs)	Proposed Remaining Life 01/01/12 (Yrs)	Current Approved Net Salvage 01/01/11 (%)	Proposed Net Salvage 01/01/12(%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Alliant/Tech											
E344	Generators	1.8	0.8	0.0	0.0	EG002-D-07-251	3.0	N/A	N/A	1	N/A
Angus C. Anson Unit 2 & 3											
E341	Structures & Improvements	24.4	23.4	-4.5	-4.5	EG002-D-05-288	15.6	EG002-D-10-173	5.5	0	1
E342	Fuel Holders, Producers & Accessories	8.8	7.8	-4.4	-4.4	EG002-D-05-1247	25.0	EG002-D-10-173	-4.4	0	1
E344	Generators	8.8	7.8	-4.4	-4.4	EG002-D-05-1247	25.0	EG002-D-10-173	-4.4	0	1
E345	Accessory Electric Equipment	8.8	7.8	-4.4	-4.4	EG002-D-05-1247	25.0	EG002-D-10-173	-4.4	0	1
E346	Miscellaneous Power Plant Equipment	8.8	7.8	-4.4	-4.4	EG002-D-05-1247	25.0	EG002-D-10-173	-4.4	0	1
Angus C. Anson Unit 4											
E341	Structures & Improvements	24.4	23.4	-4.5	-4.5	EG002-D-05-288	15.6	EG002-D-10-173	5.5	0	1
E342	Fuel Holders, Producers & Accessories	24.4	23.4	-4.5	-4.5	EG002-D-05-288	30.0	EG002-D-10-173	-4.5	0	1
E344	Generators	24.4	23.4	-4.5	-4.5	EG002-D-05-288	30.0	EG002-D-10-173	-4.5	0	1
E345	Accessory Electric Equipment	24.4	23.4	-4.5	-4.5	EG002-D-05-288	30.0	EG002-D-10-173	-4.5	0	1
E346	Miscellaneous Power Plant Equipment	24.4	23.4	-4.5	-4.5	EG002-D-05-288	30.0	EG002-D-10-173	-4.5	0	1
Black Dog Unit 5											
E341	Structures & Improvements	21.0	20.0	-8.3	-8.3	EG002-D-02-214	30.0	EG002-D-10-173	21.7	0	1
E342	Fuel Holders, Producers & Accessories	21.0	20.0	-8.3	-8.3	EG002-D-02-214	30.0	EG002-D-10-173	-8.3	0	1
E344	Generators	21.0	20.0	-8.3	-8.3	EG002-D-02-214	30.0	EG002-D-10-173	-8.3	0	1
E345	Accessory Electric Equipment	21.0	20.0	-8.3	-8.3	EG002-D-02-214	30.0	EG002-D-10-173	-8.3	0	1
E346	Miscellaneous Power Plant Equipment	21.0	20.0	-8.3	-8.3	EG002-D-02-214	30.0	EG002-D-10-173	-8.3	0	1
Blue Lake Units 1 thru 4											
E341	Structures & Improvements	24.4	23.4	-5.2	-5.2	EG002-D-05-288	27.5	EG002-D-10-173	19.8	0	1
E342	Fuel Holders, Producers & Accessories	2.0	6.0	-11.9	-11.9	EG002-D-08-189	2.0	EG002-D-10-173	-11.9	1	1
E344	Generators	2.0	6.0	-11.9	-11.9	EG002-D-08-189	2.0	EG002-D-10-173	-11.9	1	1
E345	Accessory Electric Equipment	2.0	6.0	-11.9	-11.9	EG002-D-08-189	2.0	EG002-D-10-173	-11.9	1	1
E346	Miscellaneous Power Plant Equipment	2.0	6.0	-11.9	-11.9	EG002-D-08-189	2.0	EG002-D-10-173	-11.9	1	1
Blue Lake Units 7 & 8											
E341	Structures & Improvements	24.4	23.4	-5.2	-5.2	EG002-D-06-227	0.1	EG002-D-10-173	19.8	0	1
E342	Fuel Holders, Producers & Accessories	24.4	23.4	-5.2	-5.2	EG002-D-06-227	0.1	EG002-D-10-173	-5.2	0	1
E344	Generators	24.4	23.4	-5.2	-5.2	EG002-D-06-227	0.1	EG002-D-10-173	-5.2	0	1
E345	Accessory Electric Equipment	24.4	23.4	-5.2	-5.2	EG002-D-06-227	0.1	EG002-D-10-173	-5.2	0	1
E346	Miscellaneous Power Plant Equipment	24.4	23.4	-5.2	-5.2	EG002-D-06-227	0.1	EG002-D-10-173	-5.2	0	1
Grand Meadow Wind Project											
E340.1	Wind Rights	22.9	21.9	0.0	0.0	EG002-D-08-189	25.0	N/A	N/A	1	N/A
E341	Structures & Improvements	22.9	21.9	-8.7	-8.7	EG002-D-08-189	25.0	EG002-D-10-173	1.3	1	1
E342	Fuel Holders, Producers & Accessories	22.9	21.9	-8.7	-8.7	EG002-D-08-189	25.0	EG002-D-10-173	1.3	1	1
E344	Generators	22.9	21.9	-8.7	-8.7	EG002-D-08-189	25.0	EG002-D-10-173	1.3	1	1
E345	Accessory Electric Equipment	22.9	21.9	-8.7	-8.7	EG002-D-08-189	25.0	EG002-D-10-173	1.3	1	1
E346	Miscellaneous Power Plant Equipment	22.9	21.9	-8.7	-8.7	EG002-D-08-189	25.0	EG002-D-10-173	1.3	1	1

Xcel Energy
Historical Comparison of Changes to Remaining Lives
Electric Other Production

Account	Description	Current Approved Remaining Life 01/01/11 (Yrs)	Proposed Remaining Life 01/01/12 (Yrs)	Current Approved Net Salvage 01/01/11 (%)	Proposed Net Salvage 01/01/12 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Granite City											
E341	Structures & Improvements	2.0	6.0	-38.8	-38.8	EG002-D-08-189	3.0	EG002-D-10-173	21.2	1	1
E342	Fuel Holders, Producers & Accessories	2.0	6.0	-38.8	-38.8	EG002-D-08-189	3.0	EG002-D-10-173	-38.8	1	1
E344	Generators	2.0	6.0	-38.8	-38.8	EG002-D-08-189	3.0	EG002-D-10-173	-38.8	1	1
E345	Accessory Electric Equipment	2.0	6.0	-38.8	-38.8	EG002-D-08-189	3.0	EG002-D-10-173	-38.8	1	1
E346	Miscellaneous Power Plant Equipment	2.0	6.0	-38.8	-38.8	EG002-D-08-189	3.0	EG002-D-10-173	-38.8	1	1
High Bridge											
E341	Structures & Improvements	27.4	26.4*	-3.1	-3.1	EG002-D-08-189	30.0	EG002-D-10-173	6.9	1	1
E342	Fuel Holders, Producers & Accessories	27.4	26.4*	-3.1	-3.1	EG002-D-08-189	30.0	EG002-D-10-173	6.9	1	1
E344	Generators	27.4	26.4*	-3.1	-3.1	EG002-D-08-189	30.0	EG002-D-10-173	6.9	1	1
E345	Accessory Electric Equipment	27.4	26.4*	-3.1	-3.1	EG002-D-08-189	30.0	EG002-D-10-173	6.9	1	1
E346	Miscellaneous Power Plant Equipment	27.4	26.4*	-3.1	-3.1	EG002-D-08-189	30.0	EG002-D-10-173	6.9	1	1
Irwin Hills											
E341	Structures & Improvements	16.0	15.0	-11.0	-11.0	EG002-D-10-173	10.0	EG002-D-10-173	19.0	2	1
E342	Fuel Holders, Producers & Accessories	16.0	15.0	-11.0	-11.0	EG002-D-10-173	10.0	EG002-D-10-173	-11.0	2	1
E344	Generators	16.0	15.0	-11.0	-11.0	EG002-D-10-173	10.0	EG002-D-10-173	-11.0	2	1
E345	Accessory Electric Equipment	16.0	15.0	-11.0	-11.0	EG002-D-10-173	10.0	EG002-D-10-173	-11.0	2	1
E346	Miscellaneous Power Plant Equipment	16.0	15.0	-11.0	-11.0	EG002-D-10-173	10.0	EG002-D-10-173	-11.0	2	1
Key City											
E341	Structures & Improvements	2.0	6.0	-38.6	-38.6	EG002-D-08-189	3.0	EG002-D-10-173	-18.6	1	1
E342	Fuel Holders, Producers & Accessories	2.0	6.0	-38.6	-38.6	EG002-D-08-189	3.0	EG002-D-10-173	-18.6	1	1
E344	Generators	2.0	6.0	-38.6	-38.6	EG002-D-08-189	3.0	EG002-D-10-173	-18.6	1	1
E345	Accessory Electric Equipment	2.0	6.0	-38.6	-38.6	EG002-D-08-189	3.0	EG002-D-10-173	-18.6	1	1
E346	Miscellaneous Power Plant Equipment	2.0	6.0	-38.6	-38.6	EG002-D-08-189	3.0	EG002-D-10-173	-18.6	1	1
Noble Wind Project											
E340.1	Wind Rights	24.9	23.9	0.0	0.0	EG002-D-10-173	25.0	N/A	-8.7	1	N/A
E341	Structures & Improvements	24.9	23.9	-8.7	-8.7	EG002-D-10-173	25.0	EG002-D-10-173	-8.7	1	1
E342	Fuel Holders, Producers & Accessories	24.9	23.9	-8.7	-8.7	EG002-D-10-173	25.0	EG002-D-10-173	-8.7	1	1
E344	Generators	24.9	23.9	-8.7	-8.7	EG002-D-10-173	25.0	EG002-D-10-173	-8.7	1	1
E345	Accessory Electric Equipment	24.9	23.9	-8.7	-8.7	EG002-D-10-173	25.0	EG002-D-10-173	-8.7	1	1
E346	Miscellaneous Power Plant Equipment	24.9	23.9	-8.7	-8.7	EG002-D-10-173	25.0	EG002-D-10-173	-8.7	1	1
Riverside											
E341	Structures & Improvements	28.2	27.2*	-5.0	-5.0	EG002-D-09-160	24.2	EG002-D-10-173	5.0	1	1
E342	Fuel Holders, Producers & Accessories	28.2	27.2*	-5.0	-5.0	EG002-D-09-160	29.6	EG002-D-10-173	5.0	1	1
E344	Generators	28.2	27.2*	-5.0	-5.0	EG002-D-09-160	29.6	EG002-D-10-173	5.0	1	1
E345	Accessory Electric Equipment	28.2	27.2*	-5.0	-5.0	EG002-D-09-160	29.6	EG002-D-10-173	5.0	1	1
E346	Miscellaneous Power Plant Equipment	28.2	27.2*	-5.0	-5.0	EG002-D-09-160	29.6	EG002-D-10-173	5.0	1	1
United Hospital											
E344	Generators	6.7	5.7	0.0	0.0	N/A	N/A	N/A	N/A	0	N/A
Wind-to-Battery System											
E342	Fuel Holders, Producers & Accessories	13.0	12.0	0.0	0.0	EG002-D-09-160	15.0	N/A	N/A	1	N/A

*Note on High Bridge and Riverside: A life extension of 10 years has been proposed for each plant in a Settlement to the Company's 2010 Electric Rate Case. These life extensions have not been shown on this schedule, but would bring remaining lives to 36.4 years for High Bridge and 37.2 years for Riverside.

Gas Production

Account	Description	Current Approved Remaining Life 01/01/11 (Yrs)	Proposed Remaining Life 01/01/12 (Yrs)	Current Approved Net Salvage 01/01/11 (%)	Proposed Net Salvage 01/01/12(%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Maplewood											
G305	Structures & Improvements	9.0	8.0	-17.0	-17.0	EG002-D-10-173	4.0	EG002-D-05-288	-7.0	2	0
G311	LP Gas Equipment	9.0	8.0	8.0	8.0	EG002-D-10-173	4.0	EG002-D-05-288	-7.0	2	0
G320	Other Equipment	9.0	8.0	0.0	0.0	EG002-D-10-173	4.0	EG002-D-05-288	-10.0	2	0
Sibley											
G305	Structures & Improvements	9.0	8.0	-1.0	-1.0	EG002-D-10-173	4.0	EG002-D-05-288	9.0	2	0
G311	LP Gas Equipment	9.0	8.0	8.0	8.0	EG002-D-10-173	4.0	EG002-D-05-288	-7.0	2	0
G320	Other Equipment	9.0	8.0	-1.0	-1.0	EG002-D-10-173	4.0	EG002-D-05-288	-11.0	2	0
Wescott											
G305	Structures & Improvements	9.0	8.0	-3.0	-3.0	EG002-D-10-173	2.0	EG002-D-05-288	7.0	2	0
G311	LP Gas Equipment	9.0	8.0	1.0	1.0	EG002-D-10-173	2.0	EG002-D-05-288	-9.0	2	0
G320	Other Equipment	9.0	8.0	3.0	3.0	EG002-D-10-173	2.0	EG002-D-05-288	3.0	2	0

Xcel Energy
Historical Comparison of Changes to Remaining Lives

Gas Storage

Account	Description	Current Approved Remaining Life 01/01/11 (Yrs)	Proposed Remaining Life 01/01/12 (Yrs)	Current Approved Net Salvage 01/01/11 (%)	Proposed Net Salvage 01/01/12 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Wescott											
G361	Structures & Improvements	7.0	6.0	-10.0	-10.0	EG002-D-08-189	4.0	EG002-D-79-851	-10.0	1	0
G362	Gas Holders	7.0	6.0	5.0	5.0	EG002-D-08-189	4.0	EG002-D-79-852	5.0	1	0
G363	Purification Equipment	7.0	6.0	1.0	1.0	EG002-D-08-189	4.0	EG002-D-05-288	-4.0	1	0
G363.1	Liquefaction Equipment	7.0	6.0	2.0	2.0	EG002-D-08-189	4.0	EG002-D-05-288	-3.0	1	0
G363.2	Vaporizing Equipment	17.0	16.0	2.0	2.0	EG002-D-98-221	30.0	EG002-D-05-288	-3.0	0	0
G363.3	Compressor Equipment	7.0	20.0	2.0	2.0	EG002-D-08-189	4.0	EG002-D-05-288	-8.0	1	0
G363.4	Measuring & Regulating Equipment	7.0	6.0	6.0	6.0	EG002-D-08-189	4.0	EG002-D-05-288	6.0	1	0
G363.5	Other Equipment	7.0	6.0	0.0	0.0	EG002-D-08-189	4.0	EG002-D-79-852	0.0	1	0

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Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy Department of Commerce 1
Campbell/Michelle St Pierre

Date Received: April 3, 2012

Question:

Subject: Overall impact to annual depreciation expense

Reference: Depreciation Filing, Page 2; Docket No. E002/GR-10-971, November 14, 2011 Settlement Agreement, Page 9

Please reconcile the overall impact of the decrease of \$6,393,440 in depreciation expense as you provided in the 2012 Depreciation Study with the \$4.5 million decrease in revenue requirement on the Settlement Agreement of the most recent electric rate case (Docket No. E002/GR-10-971). Please include a detailed break out of the \$6,393,440 and an explanation for each component.

Response:

The calculation of the impact of the changes in this remaining life filing is fundamentally different from the revenue requirement that was shown as a part of the Settlement Agreement in the electric rate case. The numbers presented in this filing are based on actual plant and reserve balances as of January 1 2012, and depreciation numbers are presented for the total Company. The numbers presented in the Settlement Agreement are based on the 2011 test year data that was completed in 2010 for the State of Minnesota jurisdiction.

The \$4.5 million decrease in Minnesota jurisdictional revenue requirements identified in the Settlement Agreement is the 2011 revenue requirement impact of the change in lives for our High Bridge and Riverside plants. Our Remaining Life filing identifies a \$6.4 million decrease in total NSPM 2012 depreciation expense for these same two plants. The revenue requirement impact included in the Settlement Agreement reflects the full impact of the change in depreciation rates (depreciation expense as well as return on rate base) while the change in depreciation shown in the Remaining Life filing is the depreciation expense impact only, for the total Company.

The \$4.5 million decrease in Minnesota jurisdictional revenue requirements for our High Bridge and Riverside plants was calculated based on an estimated total NSPM change in 2011 depreciation expense of \$6,304,192.

For a detailed breakdown of the depreciation change for High Bridge and Riverside in the Remaining Life filing, please see Page 10 of Attachment B to the filing.

Response By: Brandon Kirschner
Title: Senior Accounting Analyst
Department: Capital Asset Accounting
Telephone: 612-215-5361
Date: April 16, 2012

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Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy Department of Commerce 2
Campbell/Michelle St Pierre

Date Received: April 3, 2012

Question:

Subject: Wescott LNG Plant- replacement of refrigerated compressor unit

Reference: Depreciation Filing, Page 7

- a) Please provide detailed cost information and calculations that support the \$14.5 million forecasted replacement cost of the refrigerated compressor unit.
- b) Please provide supporting information like manufacturer's warranty or any other information to support the proposed 20-year life extension of the Wescott LNG Plant.
- c) Fully explain why Xcel is replacing the Wescott refrigerated compressor unit. Provide all engineering and/or cost/benefit studies done to support the decision to replace the unit.
- d) Fully explain the Company's plan for the compressor unit that is being retired.

Response:

- a) The \$14.5 million dollar amount estimated in the petition was the total forecasted additions for 2012 at the Wescott LNG Plant. This included small auxiliary projects not specifically connected to the replacement of the refrigerated compressor unit. The breakdown of all 2012 forecasted additions is shown below:

Component	Cost
-----------	------

Siemens Turbine/Compressor	\$7.0 Million
Kobelco Auxiliary Compressors	2.1 Million
Engineering Contractor	0.8 Million
Electrical Service Upgrade	1.0 Million
Motor Control Center Gear	0.3 Million
Construction	1.3 Million
Commissioning/Training	1.0 Million
Auxiliary Additions	0.5 Million
AFUDC	0.5 Million
Total	\$14.5 Million

- b) The 20 year life extension for the Wescott LNG plant is driven by the complete replacement of the refrigeration compressor, piping and integrity testing of existing components. There is no specific timeframe of operation specified by the manufacturer. Company personnel believe based on historical experience that a new compressor unit can operate at least the length of time represented by the proposed remaining life for the plant. The refrigeration compressor is the main component of the natural gas liquefaction system and the replacement compression components represent 75% of the value of the liquefaction system. Also the entire LNG plant's primary electric substation has been replaced by new transformers, wiring, and electrical switches. This along with the major electrical motor control center switchgear replacement extends the usable life of the plant with reliable operation for many years.
- c) For a detailed discussion of why the Company believes the replacement of the Compressor unit is the best option, please see Attachment 1. This information was provided as a response to an information request in Docket No. G002/PA-11-902.
- d) The Company initially intended to sell the old engine as is. The engine was marketed for an extended period of time but no interest was generated. The engine was instead scrapped and all spare parts in inventory were sold. This scrap sale was discussed fully with the Commission in Docket No. G002/PA-11-902.

Response By: Brandon Kirschner
Title: Senior Accounting Analyst

Department: Capital Asset Accounting
Telephone: 612-215-5361
Date: April 16, 2012

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Xcel Energy

Docket No.: E002/PA-11-902

Response To: Marlon Griffing & Michelle Department of Commerce 2
St. Pierre

Date Received: September 13, 2011

Question:

Reference: Initial Filing by Jody Londo

Ms. Londo states on page 3, Section IV.B, paragraph 2:

Our analysis indicated that replacing the current Unit with a gas turbine for the primary gas stream, and smaller electric-driven compressors to handle the other two gas streams is the most cost-effective solution.

Please provide the cost-benefit analysis underlying the decision to replace the current Unit with the chosen option. Of particular interest is the cost per therm or other appropriate unit of natural gas with the current Unit and the expected cost per therm of the chosen option.

Response:

In 2009, the Company identified the following three options to replace the C101 Unit:

1. a more efficient gas turbine driven compressor;
2. an electric driven compressor; or
3. do not replace the Unit (eventually discontinuing the use of the LNG plant) and purchase additional gas pipeline supply.

As shown below, we compared the total capital and operating costs of each option. As labor costs would be the same under for the first two options, the Fuel O&M costs described below refer to the fuel costs to operate the compressor. The operating costs were based on the hypothetical assumption that the plant would be filled completely each year. Using that assumption, the current unit annual Fuel O&M cost would be \$840,000 per year, or approximately \$0.04/therm. As explained below, labor costs for the third option are less, and are shown by a credit amount to account for the difference. To create an operating cost per therm, we divided the annual operating costs

assuming the plant would be filled completely each year (beginning with the operation of a new unit in 2012) by the plant capacity of 2.1 million decatherms.

Gas Turbine Option

We evaluated a newer, more efficient gas turbine as a replacement alternative, and found it to be the lowest cost option of all of the alternatives. This option allowed us to use the existing infrastructure, and replacing the old C101 Unit with a more efficient gas turbine also reduced nitrous oxide emissions.

Gas Turbine (new)	\$'s in 1,000						
	2010	2011	2012	2013	2014	2015-29	Total
Capital	\$ 260	\$ 6,600	\$ 5,900	\$ -	\$ -	\$ -	\$ 12,760
Fuel O&M	\$ 840	\$ 840	\$ 740	\$ 740	\$ 740	\$ 11,100	\$ 15,000
Fuel O&M/Therm	-	-	\$ 0.035	\$ 0.035	\$ 0.035	\$ 0.035	\$ 0.035

Electric Drive Option

We evaluated an 8,000 HP electric motor-driven compressor as a replacement alternative and found it to be more expensive than the gas turbine option. We determined that adding this electric motor driven compressor would also require additional upgrades to the electric distribution system to supply this load.

Electric Motor	\$'s in 1,000						
	2010	2011	2012	2013	2014	2015-29	Total
Capital	\$ 300	\$ 10,000	\$ 2,800	\$ -	\$ -	\$ -	\$ 13,100
Fuel O&M	\$ 840	\$ 840	\$ 1,200	\$ 1,200	\$ 1,200	\$ 18,000	\$ 23,280
Fuel O&M/Therm	-	-	\$ 0.057	\$ 0.057	\$ 0.057	\$ 0.057	\$ 0.057

Retire Wescott and Purchase Additional Capacity Option

Another alternative that we reviewed was the purchase of additional firm 12-month pipeline capacity in lieu of operating the LNG plant. In addition to questions regarding the availability and timing of the capacity purchase, the cost far exceeded the other options. We included the current labor to operate the plant as an O&M savings under this option.

Purchased Capacity	\$'s in 1,000						
	2010	2011	2012	2013	2014	2015-29	Total
Pipeline Capacity			\$ 18,025	\$ 18,025	\$ 18,025	\$ 270,375	\$ 324,450
O&M Cost/(Savings)	\$ 840	\$ 840	\$ (1,400)	\$ (1,400)	\$ (1,400)	\$ (21,000)	\$ (23,520)

Response By: Jim Goodchild
 Title: Manager, Gas Plants
 Department: Gas Production
 Telephone: 651-688-4065
 Date: September 26, 2011

Michelle St. Pierre
Financial Analyst
Division of Energy Resources
MN Department of Commerce

1) Did the gas turbine option in shown the response to IR 2, Attachment 1, page 2, include the auxiliary projects?

No. However, these auxiliary projects were necessary to complete the replacement of the refrigerated compressor unit. Due to the increase in the electrical service required for additional electric driven compressors, the electric motor driven fire pump motor and motor controller needed to be exchanged in order to meet the fire protection requirements for the gas plant.

2) Is the Siemens Turbine/Compressor for \$7 M the refrigerated compressor?

Yes. The actual cost of the turbine/compressor package, inlet filtration system, ventilation cooling system, and exhaust system, along with delivery and setup of these components comprise the \$7M.

3) How does the \$14.5 million estimated additions for 2012 compare to the 2012 capital additions of \$5,900,000 (shown in IR 2, Attachment 1, page 2)?

The \$14.5 million amount represents the estimated amount of plant to be placed in service in 2012 at the Westcott LNG plant per our latest projections. The \$5,900,000 represents the estimated capital expenditures only for 2012 at the Westcott LNG plant per the cost benefit analysis as shown in IR2, Attachment 1, page 2. Thus, the comparison is being made between additions to plant in service for 2012 (which in this instance represent the entire cost of the project) and capital expenditures for 2012 (expenditures for only one year). A better comparison would be the total estimated cost of the project (including the auxiliary projects) of \$14.5 million per our latest projections versus the total estimated cost of the project (excluding auxiliary projects) of \$12.76 million per the cost-benefit analysis. It should also be noted that the estimated amount of plant to be placed in service of \$14.5 million includes allowance for funds used during construction (AFUDC), which is not included in the \$12.76 million total estimated cost of the project per the cost-benefit analysis.

4) What were there any capital additions made in 2011 related to the refrigerated compressor unit project? If any, please provide the amount and cite to where this 2011 addition is shown in the depreciation filing.

There was \$263,298 in capital additions closed to plant in service related to the refrigerated compressor unit project in 2011. This amount is specifically cited in Attachment C, Page 2 of 2, in the depreciation filing. It is the sum of additions to FERC Account 363.2, Vaporizing Equipment for \$183,766, and to FERC Account 363.5, Other Equipment for \$79,532. It should be noted that the refrigerated compressor unit project

is scheduled to be completed in the second quarter of 2012 and as such, the majority of the dollars related to this project will then be placed in service

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Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy
Campbell/Michelle St Pierre

Department of 3
Commerce Revised

Date Received: April 3, 2012

Question:

Subject: Minnesota Valley- Change of Net Salvage Rate from -101.9% to -169.0%

Reference: Depreciation Filing, Page 7 and 8

- a) The Company proposes to increase the net salvage recovery of demolition based on new budgetary quotes from four outside contractors to perform demolition, remediation and decommissioning work on Minnesota Valley, please provide copies of the quotes from the four contractors and fully explain how they compare to the \$18,757,000 total estimate Xcel provided in the 2012 Depreciation Study, page 8.
- b) Please explain how contractor will be selected by Xcel.
- c) Please provide schedule for when work will occur and be completed.

Response:

- (a) As reflected in our filing, the components of the remaining decommissioning, remediation and demolition work for the power plant are as follows:

	Current Estimate
Asbestos abatement	\$ 4,500,000
Demolition w/ scrap credit	\$ 3,081,000
Site work	\$ 750,000
Oversight and Administrative	\$ 2,544,000
Contingency	\$ 2,651,000
Escalation	\$ 2,476,000

Coalyard closure	\$ 1,875,000
Hazardous material abatement	\$ 880,000
Total=	\$ 18,757,000

The costs listed for several components of the costs listed above were based upon budgetary proposals from contractors, as well as the Company's experience. Those components were:

- Asbestos abatement.
- Demolition w/scrap credit.
- Site work.

In addition, the Company considered the scope of work, as well as the duration to complete the work, as set forth in budgetary proposals to internally develop the following cost components:

- Contingency.
- Escalation.
- Oversight and Administrative.

Other components were not based upon project specific quotes from contractors but were internally developed estimates. Those components were:

- Coalyard closure.
- Hazardous material abatement.

The Company received budgetary proposals from: NCM Demolition ("NCM"); Brandenburg Industrial Service Company ("Brandenburg"); Rachel Contracting ("Rachel"); and Veit Specialty Contracting and Waste Management ("Veit"). A budgetary quote for manual demolition of the plants two steel stacks was also received from Hamon Custodis. All proposals are included in Trade Secret Attachment A.

1. *Asbestos Abatement (\$4.5 million)*

Proposals for Asbestos Abatement were received from NCM, Brandenburg, Rachel and Veit. In addition, the Company obtained a cost estimate from our internal asbestos abatement entity, Xcel Energy Supplement Maintenance and Construction. The Company used this input to enhance the accuracy of the estimate based on its direct experience with the asbestos abatement at the

Minnesota Valley plant and knowledge of the current site conditions. The five proposals created a range of *[TRADE SECRET BEGINS TRADE SECRET ENDS]*. The resulting cost component for asbestos abatement of \$4.5 million reflects our belief that the cost of asbestos abatement will be higher than estimated by the contractors based upon knowledge of the scope, site conditions, and our experience at High Bridge and Riverside.

2. Demolition w/ scrap credit (\$3.08 million).

The proposals we received were based upon assumptions of tonnage of steel involved in the demolition and a rate of credit for the scrap steel. Some proposals used different assumptions. To make the proposals more comparable, the Company "normalized" the proposals to reflect a consistent tonnage of steel and scrap steel credit rate. We also normalized all proposals to consider the costs required to manually demolish the two steel stacks on top of the plant, an assumption that varied between the proposals. Through this process, a range of costs for demolition, including scrap steel credit, of *[TRADE SECRET BEGINS TRADE SECRET ENDS]*. The resulting cost component for demolition with scrap metal credit of \$3.08 million is the arithmetic average of the four adjusted proposal prices.

3. Site work (\$750,000)

The costs of backfilling foundations, as well as site restoration of the demolition areas, are included in the "site work" component. Only two of the four proposals we received included a breakout of the backfill/restoration costs, *[TRADE SECRET BEGINS TRADE SECRET ENDS]*. Additional internally estimated costs were included for missing scope of work in the proposals, such as flood protection restoration. The plant currently serves as part of the flood protection system for the substation that will remain in service after the demolition project is complete. The work necessary to maintain flood protection was not included in the contractors' proposals. Therefore, the Company included this component of work as a part of the \$750,000 site work cost component.

4. Oversight and Administrative (\$2.544 million)

Although we expect contractors to perform the demolition, decommissioning and remediation work at Minnesota Valley, the Company will incur additional costs for oversight and administration of the work. Examples of the type of activities that

fall under this category are: project management, procurement, engineering support, safety, and environmental compliance. The amount of oversight and administrative work reflects the scope of work and time to complete the work, as set forth in the contractor proposals. This cost estimate also reflects our experience in prior decommissioning, dismantling and abatement at the High Bridge, Riverside, and Minnesota Valley plants.

5. Escalation (\$2.476 million)

The escalation component is based upon the overall project schedule developed from the duration of time presented in the contractors' proposals and clarifications. The proposals and internally developed estimates are in 2011 dollars.

6. Contingency (\$2.651 million)

It is normal business practice to include contingencies in capital project estimates. Contingency costs are intended to account for unplanned or uncertain costs that arise during the construction process. The Company typically assigns a particular percentage to project cost estimates in order to arrive at a contingency figure. We used the same process for the contingency component of the decommissioning, remediation and demolition at Minnesota Valley.

7. Coalyard Closure (\$1.875 million)

This component was an internally developed estimate based on past experience on coal yard closure projects at Riverside and High Bridge. Costs used to develop this estimate are based on actual contract values for work completed in the ash pond closure work at the Minnesota Valley site in 2010 and 2011.

8. Hazardous material abatement (\$880,000)

This component was an internally developed estimate based on past experience on other projects and accounts for scope beyond what was included in the contractors proposals.

(b) The Company utilizes a formal bidding process to hire contractors to perform work such as the decommissioning, remediation and demolition work at Minnesota Valley. We expect to seek formal bids in the first quarter of 2013. We will select one or possibly multiple contractors to perform the work.

(c) We expect the decommissioning, remediation and demolition work at Minnesota Valley to begin shortly thereafter and be completed by the end of 2015.

Please Note: This response was revised to remove the Trade Secret designation of estimated costs for certain work items.

Response By: Darin W. Schottler
Title: Manager
Department: Plant Services
Telephone: 612-330-2994
Date: May 2, 2012
Revised June 22, 2012

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Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy Department of Commerce 4
Campbell/Michelle St Pierre

Date Received: April 3, 2012

Question:

Subject: Riverside and High Bridge Power Plants

Reference: Depreciation Filing, Page 10 and 11

- a. Please provide supporting documents like manufacturer's warranty and any other information to support the Company's proposal to extend the remaining life of High Bridge from 26.4 year to 36.4 years, or a 10 year increase in the remaining life.
- b. Please provide supporting documents like manufacturer's warranty and any other information to support the Company's proposal to extend the remaining life of Riverside from 27.2 years to 37.2 years, or a 10 year increase in the remaining life.

Response:

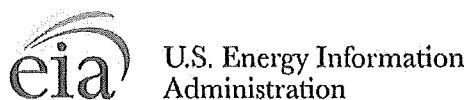
The following response is in reference to both questions a. and b. above.

Generally, the Company reviews the remaining life of a generating plant based on existing investments; and proposes life extensions as the time approaches to make the additional investments that will support continued operation beyond the current remaining life. However, for both the High Bridge and Riverside Plants, based on industry standards, it can be expected that, with additional investment, these two plants will continue operations for 40 years. In addition, it can also be expected that, when needed, the Company will make the additional investment. These two reasonable assumptions support lengthening the remaining lives of these plants by 10 years.

Our analysis did not include review of documents such as a manufacturer's warranty and we do not have any such documents in support of our request. However, the US Energy Information Administration published in Today in Energy on June 16, 2011,

charts presenting data on the age and capacity of existing electric generators by fuel type as of the end of 2010. This information shows that across the industry a significant number of existing gas generation facilities between 30 and 50 years old continued to be in operation at the end of 2010. Therefore, we believe that, with additional investment as required, the relatively newer High Bridge and Riverside Plants should be able to operate at least as long as 30 to 50 year old gas plants in operation today. DOC IR-04, Attachment 1 contains a copy of this article.

Response By: Lisa Perkett
Title: Director
Department: Capital Asset Accounting
Telephone: 612-330-6950
Date: April 16, 2012

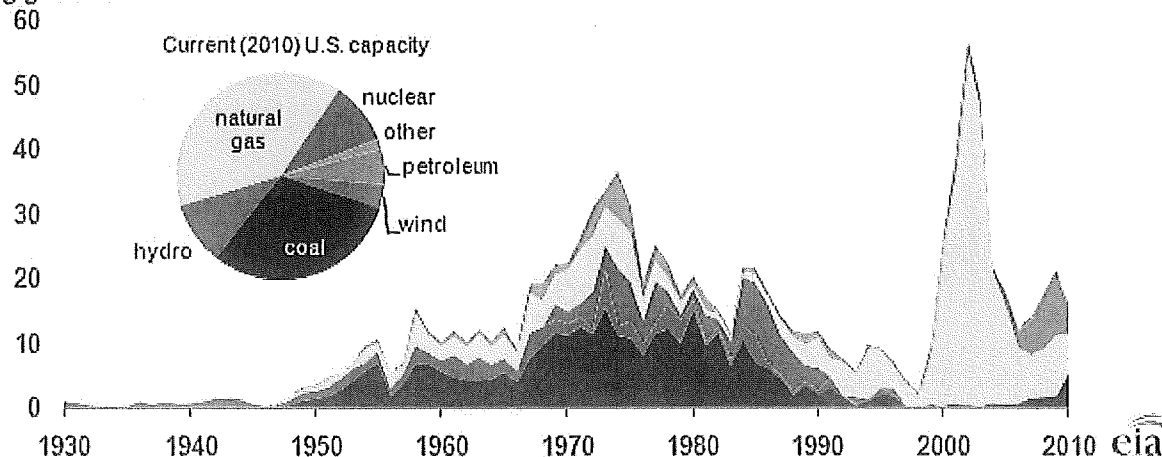


Today in Energy

June 16, 2011

Age of electric power generators varies widely

Current (2010) capacity by initial year of operation and fuel type
gigawatts



Source: U.S. Energy Information Administration, Form EIA-860 Annual Electric Generator Report , and Form EIA-860M (see Table ES3 in the March 2011 Electric Power Monthly)

Note: Data for 2010 are preliminary. Generators with online dates earlier than 1930 are predominantly hydroelectric. Data include non-retired plants existing as of year-end 2010. This chart shows the most recent (summer) capacity data for each generator. However, this number may change over time, if a generator undergoes an uprate or derate.

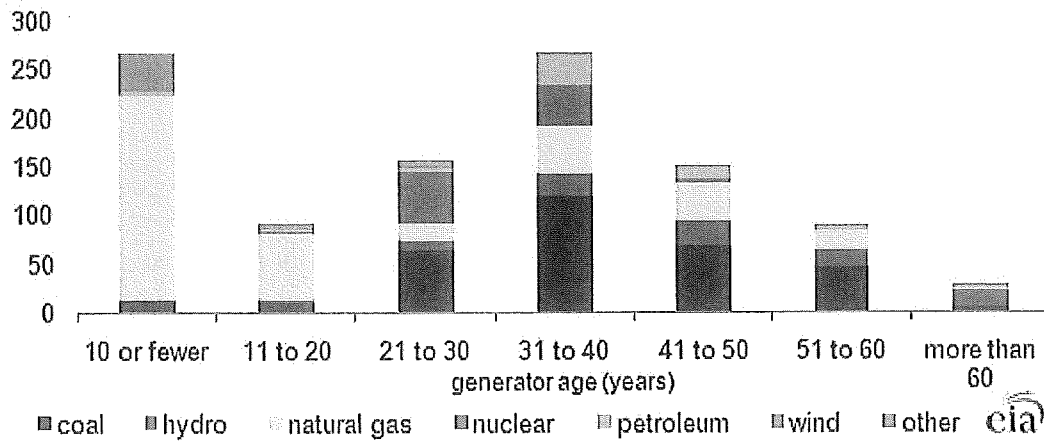
[Download CSV Data](#)

The current fleet of electric power generators has a wide range of ages. The oldest power plants tend to be hydropower generators. Most coal-fired plants were built before 1980. There was a wave of nuclear plant construction from the late 1960s to about 1990. The most recent waves of generating capacity additions include natural gas-fired units in the 2000s and renewable units, primarily wind, coming online in the late 2000s.

An upcoming series of Today in Energy articles will examine trends in generating capacity additions by fuel type, for coal, hydro, nuclear, natural gas, petroleum, and wind. The 'other' category includes solar, biomass, and geothermal generators, as well as landfill gas, municipal solid waste, and a variety of small-magnitude fuels such as byproducts from industrial processes (e.g., black liquor, blast furnace gas).

About 530 GW, or 51% of all generating capacity, were at least 30 years old at the end of 2010 (see chart below). Most gas-fired capacity is less than 10 years old, while 73% of all coal-fired capacity was 30 years or older at the end of 2010.

Age and capacity of existing electric generators by fuel type, as of year-end 2010
gigawatts



Source: U.S. Energy Information Administration, Form EIA-860 Annual Electric Generator Report , and Form EIA-860M (see Table ES3 in the March 2011 Electric Power Monthly)

Download CSV Data

tags: age of generators series , capacity , electricity

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Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy Department of Commerce 5
Campbell/Michelle St Pierre

Date Received: April 3, 2012

Question:

Subject: Sherco 3

Reference: Depreciation Filing, Page 11

- a) Please provide a break out of the approximately \$23 million in costs of major projects completed for Sherco and identify in what Unit each project relates to (Units 1, 2 or 3).
- b) Please explain why Xcel's proposed accounting and ratemaking described on page 11 of Xcel's depreciation filing is reasonable and meets the criteria of Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, specifically Account 105, Electric plant held for future use, and is consistent with Minnesota Public Utilities Commission past practice of dealing with plant held for future use.
- c) What is the Company's plan for Sherco 3 that supports inclusion in FERC Account 105, Electric plant held for future use?

Response:

- a) The \$23 million in costs of major projects completed and included within FERC Account 105, Electric Plant Held for Future Use, all relate to Sherco Unit 3. The amounts reflect installation of equipment to replace various Sherco Unit 3 turbine sections with a more efficient design and increased steam flow allowing a 20-40 MW increase of rating capacity.
- b) Xcel Energy's major projects included within FERC Account 105, Electric Plant Held for Future Use, are specific to Sherco Unit 3 and were completed in November 2011. Due to the significant failure at Sherco Unit 3 in November 2011, these projects are not currently in use and will not be in use until the unit returns to operations at which point these projects will be operational. Since these assets have not been used, depreciating the assets before their initial use would not be appropriate. Also, FERC rules state that this account shall be used for the original cost of electric plant owned and held for future use under a definitive plan by the company. Since Xcel Energy has not used these assets in electric generation and has a definitive plan to use them once Sherco Unit 3 returns to operations, the accounting treatment is deemed reasonable.
- c) Xcel Energy is currently repairing Sherco Unit 3 for the damage performed by the failure and intends to resume operations as soon as the unit is deemed to be safe and fully operational. At that time, the assets currently held in FERC Account 105 will be placed into service and depreciated over the remaining life. At this time, Xcel Energy is unable to definitively state when Sherco Unit 3 is expected to return to operations.

Response By: Andy Sawyer
Title: Senior Analyst
Department: Capital Asset Accounting
Telephone: 612-215-4649
Date: 04/16/12

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Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy Department of Commerce 8
Campbell/Michelle St Pierre

Date Received: April 3, 2012

Question:

Subject: Other Production Granite City

Reference: Depreciation Filing, Page 5

- a. In Xcel's most recent rate case (Docket E002/GR10-971), the DOC asked Xcel in information request 159 the following question: "Is Xcel planning on extending the lives of its generation plants in the next two years? If yes, please identify which generation plants Xcel is planning on extending and the expected life of that extension." DOC notes that Xcel identified Black Dog and Prairie Island as generation with changes in its lives, however, no other generation was identified for life extensions. Please explain why Granite City was not identified as generation that would have its life extended in the rate case, as now requested in Xcel's February 17, 2012 Annual Remaining Life Depreciation Filing.
- b. In light of the fact that Granite City Peaking Plant only had a one year remaining life, shouldn't Xcel have been able to conclude during the rate case that either the life would need to be extended or the plant be retired in the rate case? Please explain your answer.

Response:

- a. Granite City was not identified as a generation plant in need of a life extension at the time of our response to Information Request 159 because at that time there was significant uncertainty surrounding the continued use of small peaking plants like Granite City. It was unknown whether the plant would be used past the end of 2012 so it was determined that a life extension of the plant was not prudent.

- b. There are times when the Company will know well in advance about activities which will trigger future remaining life changes. Unfortunately the process of analyzing remaining lives far into the future is not perfect. The rate case Information Request was filed on February 1, 2011, a full year before our 2012 remaining life filing, and two weeks before our 2011 filing was even submitted. While the Information Request response was intended to highlight any known changes which would be made in the future, it was not intended to be a binding statement restricting our opportunity to make more changes if other factors came to light. As we mention in the Information Request, "It is possible through the annual review process for 2012 that additional information could support changes not currently foreseen." Some of the additional information which came to light since our response to Information Request No. 159 includes the fire which disabled Sherco Unit 3 and the delay of the proposed new unit at the Black Dog plant. With the loss of production at Sherco and the delay of expected future production at Black Dog it was determined that small peaking plants like Granite City may be important as a continued production asset to ensure system reliability for customers.

Response By: Brandon Kirschner
Title: Senior Accounting Analyst
Department: Capital Asset Accounting
Telephone: 612-215-5361
Date: April 16, 2012

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Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy Department of Commerce 9
Campbell/Michelle St Pierre

Date Received: April 3, 2012

Question:

Subject: Minnesota Falls Dam Removal

Reference: Depreciation Filing, Page 9

- a. When did the Minnesota Department of Natural Resources notify Xcel that there were deficiencies in the Minnesota Falls Dam and require Xcel to develop a long-term plan to remove, repair or otherwise modify the dam to ensure its safe operation? Please provide a copy of any letters or documents that support your response.
- b. Xcel noted on page 9 of its Depreciation filing that the removal of the dam was determined to be the most cost-effective option to address deficiencies discussed above. Please provide information to support how the decision that dam removal was the most cost-effective option was reached.
- c. Has Xcel addressed its plan to remove Minnesota Falls Dam in its Integrated Resource Plan? Please explain why or why not.
- d. Please provide information and estimates from engineering consultant and three contractors for the onsite work – removal and demolition.

Response:

- a. The DNR conducts regular inspections pursuant to Minnesota Statutes 103G.515 and Minnesota Rules 6115.0360. Deficiencies are routinely identified and addressed via repair or further inspection to ensure stability. The need for more substantial work was identified

and summarized in the enclosed 2006 inspection report (Attachment A), with reference to certain elements that may have worsened since some initial identification during 2003 and 2004 inspections. The enclosed 2008 inspection report (Attachment B) reiterated the concerns and required a plan within 90 days. The enclosed 2009 letter (Attachment C) and 2009 inspection report (Attachment D) entail the options to address the DNR concerns long term: removal, overall repair, or otherwise modify (e.g. to a gradual cascade). Various meetings and correspondence occurred between and after these inspections. As follow up, we contracted Barr Engineering to conduct a feasibility study of long term options. Based on the results of the feasibility study, the decision to start the removal process was made in June 2010. During that process, we continued to indicate that we were open to serious, valid offers for a transfer in ownership.

- b. We note that since our remaining lives petition was submitted, we have received an offer from an entity to take ownership of the dam. As a part of the proposal, the Company would pay the entity approximately [***TRADE SECRET BEGINS*** ***TRADE SECRET ENDS***] and the entity would undertake ongoing responsibility for the long-term plan to remove, repair or otherwise modify the dam to ensure its safe operation. We have accepted this proposal, it will be less costly than if the Company were to remove the dam. However, an agreement must still be finalized. When we file reply comments we intend to provide an update to our remaining lives petition to reflect the status of this new development, as well as the corresponding change to our depreciation expense. Please let us know if you believe there is a better procedural course of action.
- c. The Minnesota Falls Dam has been maintained by NSP to date because it provided the reservoir for cooling water withdrawal at the Minnesota Valley plant about 1.5 miles upstream. However, there has been no hydro generation at this location for over 50 years. There is no generation equipment located at the dam. The Minnesota Valley Plant was not included in the IRP since 2004 when it was discussed as a candidate for repowering, but no longer carried MAPP accreditation.
- d. Please see our response to (b) above.

Response By: James D. Kuhn
Title: Plant Director
Telephone: 952-829-4543
Date: April 24, 2012



Minnesota Department of Natural Resources

500 Lafayette Road
St. Paul, Minnesota 55155-4032

August 1, 2006

Mr. Jim Bodensteiner
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

RE: Minnesota Falls Dam, Yellow Medicine County (NID # MN00969)

Dear Mr. Bodensteiner:

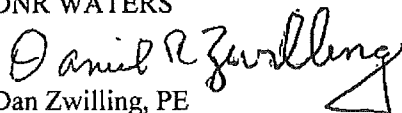
Personnel from the Minnesota DNR Division of Waters inspected the Minnesota Falls Dam in Yellow Medicine County on July 20, 2006. Such inspections are conducted on a regular basis as required by State Regulations. As you are aware, the dam is severely deteriorated, is structurally unstable in places, and needs repair. Several of these deficiencies were discussed in previous correspondence sent to you from our office in 2004. My impression during last week's inspection is that concrete cracking has worsened. Photograph 1 shows a large crack on the spillway's crest on the right side of the dam. Photograph 2 shows one of several severely deteriorated areas in the concrete abutment on the left side of the dam. Photographs 3 and 4, taken during the 2003 inspection, show head cutting of the right embankment. This area will not likely withstand a flood similar in magnitude to the 1997 flood. The primary spillway was not inspected. Xcel Energy is to have the primary spillway and the riverbed below the spillway inspected by a license engineer for structural instability, scour, and undermining. This inspection should be completed by the end of the year.

In 2004, we also recommended that the hazard classification and dam breach analysis for this dam be updated. The dam is currently classified as a "high" hazard dam. Please refer to our 2004 memo for a discussion of several items pertinent to completing the breach analysis.

The above comments are considered urgent; please contact our office within 30 days with plans to complete a detailed safety evaluation and the long-term plan for the dam. Other options may include downsizing or removing the dam. All of these options will require a permit from the DNR.

If you have questions, please call me at (651) 259-5722.

Sincerely,
DNR WATERS


Dan Zwilling, PE
Dam Safety Unit

Cc: Dave Leuthe, DNR Regional Hydrologist
Skip Wright, DNR Area Hydrologist
Jim Sehl, DNR Area Hydrologist

Attachments



DAM INSPECTION REPORT
State of Minnesota
DNR Waters

Dam Name: Minnesota Falls Dam _____
 County: Yellow Medicine _____
 NID #: MN00969 _____
 Owner: Xcel Energy _____
 Hazard Class: Class I (High) _____

Inspected by: Dan Zwilling, Dana Dostert _____
 Date: 07/20/06 _____
 Contact: Jim Bodensteiner _____
 Address: 414 Nicollet Mall, Mpls 55401 _____
 Phone Number: () _____

General Condition of Dam is: Good Fair Poor and it is: Stable Unstable Unsure

Repairs and Maintenance Needed: See cover letter.

Comment: Portions of the spillway were not inspected due to high water.

Feature	Yes	No	Remarks	Photos
I. OUTLET STRUCTURES				
A. Accumulation of debris		X		
B. Cracked or eroded concrete	X			1,2
C. Abnormal leakage	X			
D. Separated joints	X			
E. Settlement			Not surveyed	
F. Erosion at outlet			Not surveyed due to high tailwater	
G. Faulty gates or stop logs			Not inspected	
II. RIGHT EARTHEN ABUTMENT				
A. Accumulation of debris	X			
B. Cracked or eroded concrete				
C. Abnormal leakage		X		
D. Trees	X			
E. Settlement			Not surveyed	
F. Erosion	X		Head cutting. See 2003 inspection photos	
G. Other	X			

III. Emergency Spillway (None)

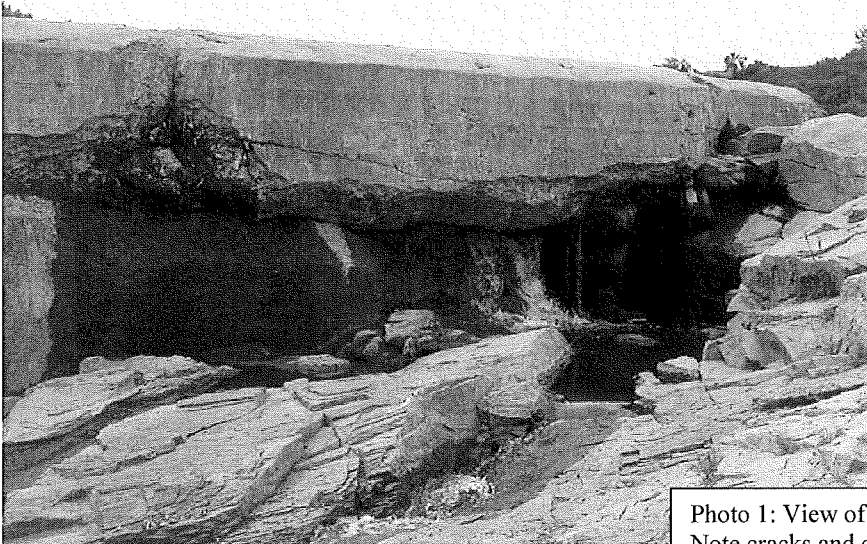


Photo 1: View of the right side of the spillway.
Note cracks and concrete deterioration.

Minnesota Falls Dam
(MN00969) on 7/20/06

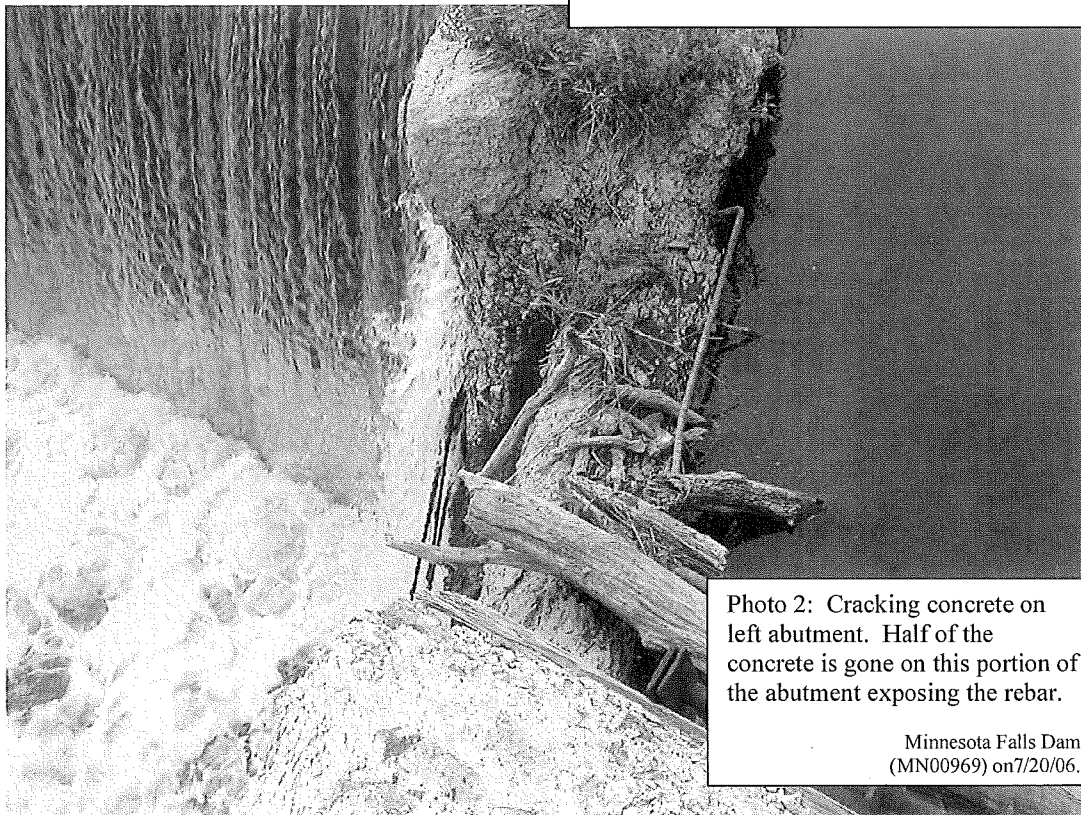


Photo 2: Cracking concrete on
left abutment. Half of the
concrete is gone on this portion of
the abutment exposing the rebar.

Minnesota Falls Dam
(MN00969) on 7/20/06.

Minnesota Falls Dam – Photos on November 19 and 20, 2003

Photos from 2003 dam inspection report.



Photo 3: Earth embankment to the right of the dam. The embankment in this area is about five feet high. A three-foot vertical erosion of the embankment is showing in the photo. The embankment has a top width of 12 feet and has no vegetation cover. The upstream portion of the embankment is 70 feet from reservoir and is filled logs (see photo below).

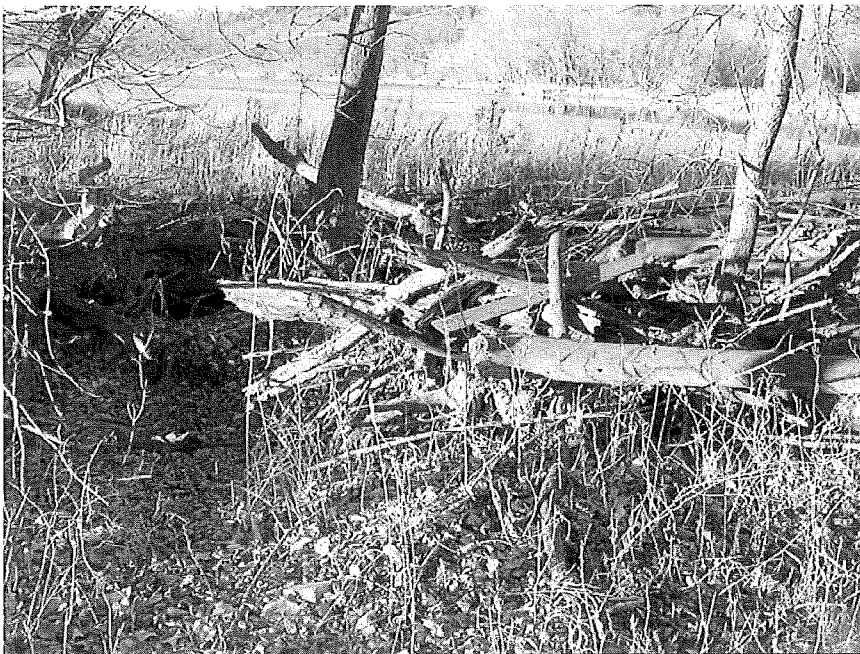
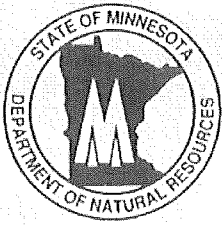


Photo 4: Looking at the upstream portion of the embankment from the top of the embankment.

Minnesota Department of Natural Resources



500 Lafayette Road
St. Paul, Minnesota 55155-
4032

October 28, 2008

Mr. Lloyd Hilgart, Plant Director
Northern States Power d/b/a Xcel Energy
411 Nicollet Avenue, MP8
Minneapolis, MN 55401-1993

SUBJECT: Minnesota Falls Dam, Yellow Medicine County (NID #MN00969)

Dear Mr. Hilgart:

Personnel from the DNR Dam Safety Unit inspected the Minnesota Falls Dam on October 23, 2008. Such inspections are conducted on a regular basis as required by State Regulations. As you are aware, the dam is severely deteriorated, is structurally unstable in places and in need of repair. The stop logs are leaking and show signs of considerable deterioration. The left concrete abutment shows major surface deterioration; especially in the area of the stop log bay. We were unable to inspect the spillway portion of the dam due to high river flows.

Allan Fandrey of Barr Engineering has informed us that Xcel Energy is considering other options rather than repairing the dam. Please contact our office within 90 days with your long-term plans to remove, repair or otherwise modify the dam to ensure its safe operation.

If you have questions or concerns, please feel free to call me at (651) 259-5722.

Sincerely,
DNR WATERS

A handwritten signature in cursive script, appearing to read 'Dan Zwilling', with a stylized flourish at the end.

Dan Zwilling, PE
Dam Safety Unit

cc: Jim Bodensteiner, Xcel Energy
Pat Flowers, Xcel Energy Water Quality Manager
Dick Rudolph, Xcel Energy Senior Plant Manager
Dave Leuthe, DNR Regional Hydrologist
Skip Wright, DNR Area Hydrologist
Jason Boyle, Dam Safety Supervisor

DNR Information: 651-296-6157 • 1-888-646-6367 • TTY: 651-296-5484 • 1-800-657-3929

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Minnesota Department of Natural Resources

500 Lafayette Road • St. Paul, MN • 55155-4037



January 28, 2009

Mr. Jim Bodensteiner
Northern States Power d/b/a Xcel Energy
411 Nicollet Avenue, MP8
Minneapolis, MN 55401-1993

RE: Follow up items from January 8, 2009 meeting on Minnesota Falls Dam (MN 00969), Yellow Medicine County

Dear Mr. Bodensteiner:

As discussed at the meeting on January 8, the DNR Dam Safety recommends that a few safety measures be completed to ensure safe operation until the dam can be removed. These recommendations are based on the premise that Xcel Energy is actively working to remove the dam.

Structural Stability

- The reinforced concrete pier that divides the stoplog section from the primary overflow spillway has severe surface deterioration. Other piers also show major deterioration. Based on the amount of deterioration, the structural integrity of the stop log bay is in doubt. The piers should be inspected in 2010 during low-flow conditions, their complete condition evaluated and upgraded as necessary.
- Barr Engineering inspected the downstream face of the primary spillway in 2006 under low flow conditions. Their report did not find structural displacement or leakage concerns. Water levels were not drawn down sufficiently to conduct a full inspection of the arch tunnels and scour at the downstream toe. These areas are to be inspected every four years under sufficiently low water levels until the dam is removed. The next inspection should be completed in 2010.
- The secondary spillway has some horizontal cracks near the crest and vertical cracks that extend the height of the spillway. The cracks should be monitored routinely and repaired if additional movement is evident.
- Various engineering reports have shown the stability of the primary spillway is close to meeting the recommended minimum sliding safety factor for usual loading conditions for low-hazard dams, but does not meet the criteria for significant or high-hazard dams. The sliding safety factor of the dam for unusual loading conditions is also below the recommended minimum value for significant and high-hazard dams. We will not mandate a structural modification to the primary spillway at this time since the dam has a good history of structural stability, there are plans to remove the structure, and the hazard classification is under review.



January 28, 2009 letter page 2

Hazard

- Buoys are to be placed upstream of the dam between May 1 and October 15 to keep the public away from the dam.
- An Operation Plan is needed to address any future drawdown for repairs or inspections. The plan should have a procedure for drawing down the reservoir and an updated contact list of those affected upstream and downstream.
- An updated Emergency Action Plan will be needed if the dam remains high hazard.
- Currently this dam is classified as a high-hazard dam. An internal memorandum by Barr Engineering on November 7, 2006 suggests this hazard class may be too high. The report shows water levels from a dam breach during the 25-year event would not reach first floor elevation for any homes below the dam. Some low-lying buildings and access roads to homes may flood. The results of this preliminary report are consistent with a significant hazard rating. However, we need to be certain that a dam failure will not cause any probable loss of life before we lower the classification. Some items needed:
 - Clarification on which hydraulic model was used and if the model results are still applicable (recent memos discuss using both the 1990 dam break and the Flood Insurance Study, how do they differ?).
 - Clarification on the assumptions and parameters used in the hydraulic model and dam break (flashboards, time to fail, breach size, in-line weir or embankment, steady or unsteady flow, etc.)
 - Impacts to houses from a 50-year and 100-yr flood with dam break, including velocities. Though we generally agree with the FERC 2-foot incremental impact guidelines, we also need to use judgment if the impacts are close to two feet since there may not be an escape route.
 - Summary table of elevations of residences, along with flood event elevations and flood event elevations with dam break for the 25-year, 50-year and 100-year events. Stream velocities at the homes should be included in the table.
 - Verification that the campground or campgrounds downstream do not exist or that they will not be impacted by a dam break.
 - Verification that ethanol plant operations would not be impacted by a dam break.
 - The predicted water surface profiles from the 1992 Yellow Medicine County Flood Insurance study should be substantiated by comparing available observed water levels from recent major floods such as the 1997 flood.
 - A short report with the above information and a recommended hazard classification.

If you have any questions, please contact me at (651) 259-5715.

Sincerely,

DNR WATERS



Jason Boyle, P.E.

State Dam Safety Engineer

cc: Dick Rudolph, Xcel Senior Plant Engineer
Lloyd Hilgart, Xcel Plant Director
Pat Flowers, Xcel Water Quality Manager
Jason Boyle, DNR Dam Safety
Lucas Youngsma & Skip Wright, Area Hydrologist
Dave Leuthe, Section Administrator



Minnesota Department of Natural Resources

500 Lafayette Road
St. Paul, Minnesota 55155-
4032

September 23, 2009

Mr. Lloyd Hilgart, Plant Director
Northern States Power d/b/a Xcel Energy
411 Nicollet Avenue, MP8
Minneapolis, MN 55401-1993

SUBJECT: Minnesota Falls Dam, (NID #MN00969) Yellow Medicine County

Dear Mr. Hilgart:

Personnel from the DNR Dam Safety Unit inspected the Minnesota Falls Dam on August 13, 2009. Such inspections are conducted on a regular basis as required by State Regulations.

The 2009 inspection was limited to the right embankment. Dam Safety noted rock riprap was placed on a previously thin, tree filled earthen embankment. This work was likely completed in the fall of 2008 or earlier this spring. Dam Safety also observed cracks in the right auxiliary spillway. Several photographs were taken to document the current size and location of cracks.

If you have questions or concerns, please feel free to call me at (651) 259-5722.

Sincerely,
DNR WATERS

A handwritten signature in cursive script, appearing to read 'Dan Zwilling', is written over the typed name.

Dan Zwilling, PE
Dam Safety Unit

cc: Jim Bodensteiner, Xcel Energy
Pat Flowers, Xcel Energy Water Quality Manager
Skip Wright, DNR Regional Hydrologist
Ethan Jenzen, DNR Area Hydrologist
Jason Boyle, Dam Safety Supervisor







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Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy Department of Commerce 10
Campbell/Michelle St Pierre

Date Received: April 3, 2012

Question:

Subject: Other Production –Blue Lake Units 1 through 4

Reference: Depreciation Filing, Page 5

- a. In Xcel's most recent rate case (Docket E002/GR10-971), the DOC asked Xcel in information request 159 the following question: "Is Xcel planning on extending the lives of its generation plants in the next two years? If yes, please identify which generation plants Xcel is planning on extending and the expected life of that extension." DOC notes that Xcel identified Black Dog and Prairie Island as generation with changes in its lives, however, no other generation was identified for life extensions. Please explain why Blue Lake Units 1 through 4 were not identified as generation that would have its life extended in the rate case, as now requested in Xcel's February 17, 2012 Annual Remaining Life Depreciation Filing.
- b. In light of the fact that Blue Lake Units 1 thru 4 Peaking Plant only had a one year remaining life, shouldn't Xcel have been able to conclude during the rate case that either the life would need to be extended or the plant be retired in the rate case? Please explain your answer.

Response:

- a. Blue Lake was not identified as a generation plant in need of a life extension at the time of our response to Information Request 159 because at that time there was significant uncertainty surrounding the continued use of small peaking plants like Blue Lake. It was unknown whether the plant would be used past the end of 2012 so it was determined that a life extension of the plant was not prudent.

- b. There are times when the Company will know well in advance about activities which will trigger future remaining life changes.

Unfortunately the process of analyzing remaining lives far into the future is not perfect. The rate case Information Request was filed on February 1, 2011, a full year before our 2012 remaining life filing, and two weeks before our 2011 filing was even submitted. While the Information Request response was intended to highlight any known changes which would be made in the future, it was not intended to be a binding statement restricting our opportunity to make more changes if other factors came to light. As we mention in the Information Request, "It is possible through the annual review process for 2012 that additional information could support changes not currently foreseen." Some of the additional information which came to light since our response to Information Request No. 159 includes the fire which disabled Sherco Unit 3 and the delay of the proposed new unit at the Black Dog plant. With the loss of production at Sherco and the delay of expected future production at Black Dog it was determined that small peaking plants like Blue Lake may be important as a continued production asset to ensure system reliability for customers.

Response By: Brandon Kirschner
Title: Senior Accounting Analyst
Department: Capital Asset Accounting
Telephone: 612-215-5361
Date: April 16, 2012

- ☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy

Docket No.: E,G002/D-12-151

Response To: Lerma La Plante/Nancy Department of Commerce 11
Campbell/Michelle St Pierre

Date Received: April 3, 2012

Question:

Subject: Other Production – Key City

Reference: Depreciation Filing, Pages 5 and 6

- a. In Xcel's most recent rate case (Docket E002/GR10-971), the DOC asked Xcel in information request 159 the following question: "Is Xcel planning on extending the lives of its generation plants in the next two years? If yes, please identify which generation plants Xcel is planning on extending and the expected life of that extension." DOC notes that Xcel identified Black Dog and Prairie Island as generation with changes in its lives, however, no other generation was identified for life extensions. Please explain why Key City was not identified as generation that would have its life extended in the rate case, as now requested in Xcel's February 17, 2012 Annual Remaining Life Depreciation Filing.
- b. In light of the fact that Key City Peaking Plant only had a one year remaining life, shouldn't Xcel have been able to conclude during the rate case that either the life would need to be extended or the plant be retired in the rate case? Please explain your answer.

Response:

- a. Key City was not identified as a generation plant in need of a life extension at the time of our response to Information Request 159 because at that time there was significant uncertainty surrounding the continued use of small peaking plants like Key City. It was unknown whether the plant would be used past the end of 2012 so it was determined that a life extension of the plant was not prudent.

- b. There are times when the Company will know well in advance about activities which will trigger future remaining life changes. Unfortunately the process of analyzing remaining lives far into the future is not perfect. The rate case Information Request was filed on February 1, 2011, a full year before our 2012 remaining life filing, and two weeks before our 2011 filing was even submitted. While the Information Request response was intended to highlight any known changes which would be made in the future, it was not intended to be a binding statement restricting our opportunity to make more changes if other factors came to light. As we mention in the Information Request, "It is possible through the annual review process for 2012 that additional information could support changes not currently foreseen." Some of the additional information which came to light since our response to Information Request No. 159 includes the fire which disabled Sherco Unit 3 and the delay of the proposed new unit at the Black Dog plant. With the loss of production at Sherco and the delay of expected future production at Black Dog it was determined that small peaking plants like Key City may be important as a continued production asset to ensure system reliability for customers. Further, after the Information Request response, the company renewed the fuel contract for the Wilmarth RDF Plant an additional five years starting in 2013, meaning that operations will likely continue at Wilmarth for at least the next six years. This continued operation at the Wilmarth plant means a continued availability of staffing for Key City, since staffing for the plant comes from the Wilmarth RDF plant.

Response By: Brandon Kirschner
Title: Senior Accounting Analyst
Department: Capital Asset Accounting
Telephone: 612-215-5361
Date: April 16, 2012

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
Public Comments**

Docket No. E,G002/D-12-151

Dated this 27th of June, 2012

/s/Sharon Ferguson

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