Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: October 24, 2017 ....**Agenda Item # **2**

Company: Northern States Power Company, dba Xcel Energy

Docket No. E,G-002/D-17-147

In the Matter of Xcel Energy's 2017 Annual Review of Remaining Lives

Issue: Should the Commission approve Xcel's 2017 Remaining Life Depreciation petition?

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Relevant Documents

Xcel - Initial Filing .... February 17, 2017
OAG - Comments... August 18, 2017
Department – Comments .... August 18, 2017
Xcel – Reply Comments .... August 28, 2017

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October 18, 2017

Statement of the Issue

Should the Commission approve Xcel's 2017 Remaining Life Depreciation petition?

Background

February 17, 2017: Xcel Energy (Xcel) filed a petition for approval of its 2017 review of remaining lives and the resulting depreciation parameters. The Company has requested the Commission approve the following:

- Modifications to the remaining lives of some of its electric production plants: Angus Anson Units 1 &2, Blue Lake Units 1-4, Granite City and St. Croix Falls;

- A new remaining life and net salvage rate for its Courtenay wind facility which went into operation in November of 2016;

- A one year's passage of time adjustment for all remaining electric and natural gas production and gas storage facilities; and

- Approval of amortization rates for the unwinding of regulatory assets that were created by previous Commission orders to address the Company's theoretical reserve surplus and better align the theoretical reserve with the actual depreciation reserve.

If the Commission were to approve Xcel's proposed changes the annual depreciation expense would increase by approximately $140,000, or 0.04 percent. The Company proposed an effective date of January 1, 2017.

August 18, 2017: The Department filed comments and recommended the Commission approve Xcel's proposed depreciation lives and salvage rates for its electric production, gas production and gas storage facilities, except for the proposed remaining life for Angus Anson Units 2 & 3. The Department recommended the Commission set a remaining life of nine year for these units.

The Department concluded that Xcel's accounting treatment of the theoretical reserve surplus amortization rates is reasonable. The Department based the recommendation in part on Xcel's explanation that the proposed treatment will have no effect on the Company's revenue requirement. If approved by the Commission, the Company should be prepared to demonstrate in future rate case and rider proceedings that there are no cost impacts to ratepayers of Xcel's accounting treatment of its theoretical reserve surplus amortization

August 18, 2017: The Minnesota Office of the Attorney General – Residential and Antitrust Division (OAG) submitted comments and stated the Company:

- Has failed to align actual and projected removal costs with the cost estimate provided in its 2015 net salvage rate study;

- Has an insufficient depreciation reserve to cover all removal costs for Black Dog Units 3 and 4; and

- Has no reason to maintain its Key City facility in a dormant state to support the continued operations of the Granite City facility.

August 28, 2017: Xcel filed reply comments and asked the Commission to approve its petition as filed on February 17, 2017.

Xcel's depreciation parameters used as the starting point in this filing were approved by the Commission in its November 13, 2015 Order in Docket No. E,G-002/D-15-46. The Commission made the parameters effective as of January 1, 2016. In this filing, the Company has reviewed the remaining lives of its electric and natural gas production and gas storage facilities as of January 1, 2017. The Company stated its analysis considered system demand, availability of fuel supplies, operating and maintenance costs and technological advancements that influence decisions about retiring electric and natural gas facilities.

The changes proposed by the Company in its Petition in this Docket would result in depreciation rates that differ from those reflected in the 2015 Rate Case.

Depreciation Statute & Rules

Minnesota Statutes Section 216B.11 and Minnesota Rules, parts 7825.0500-7825.0900 require public utilities to seek Commission approval of their depreciation practices. Utilities must also file depreciation studies at least once every five years and must use straight-line depreciation unless the utility can justify a different method. Annual depreciation study updates are required when the remaining-life technique is employed to allow the Commission the opportunity to approve changes in depreciation rates.

The Department concluded that Xcel's Petition complies with all applicable rules.

Passage of Time Adjustment

The Company began its analysis by incorporating a one-year passage of time adjustment to the 2016 remaining lives of all facilities which results in the proposed remaining lives as of January 1, 2017. The passage of time does not change the amount of the annual depreciation accrual but reflects that the Company's production facilities have aged one-year since the last depreciation filing. No party objected to the adjustment for one-year passage of time.

Changes in Remaining Lives for Production Facilities

The Company has asked the Commission to approve changes to remaining lives of four of its electric production facilities: St. Croix Falls, Angus Anson Units 2 & 3, Blue Lake Units 1-4 and

Granite City. The Company is also asking the Commission to set a remaining life and salvage rate for its Courtenay Wind farm which was placed into service in November of 2016.

St. Croix Falls

St. Croix Falls is a hydro production plant located on the St. Croix River in St. Croix Falls, Wisconsin. The plant consists of eight hydro units totaling 25.9 megawatts. NSP-Wisconsin owns the plant located on the Wisconsin side of the river and NSP-Minnesota owns the portion of the plant that is located on the Minnesota side of the river. On the Minnesota side, the plant consists of one small control house and one tainter (spillway) gate.

This property has been fully depreciated since 1996. There have not been any major capital additions to the NSP-Minnesota portion of the facility until 2016. A new remaining life was not established, even though the facility was still in service. In July 2016, the Company completed a capital project to replace the overlay wall on the Minnesota side of the river, with a capitalized value of $2.3 million.

The Company proposed capitalizing this cost rather than expensing the entire $2.3 million in 2016. Expensing a cost indicates it is included on the income statement as a one-time expense and subtracted from revenue to determine profit. This negatively affects the Company's net operating income. Capitalizing indicates that the cost has been determined to be a capital expenditure and is accounted for on the balance sheet as an asset, with only the depreciation showing up on the income statement. Amortizing the cost over 12 years eases the effect on the Company's net operating income.

In its 2015 Rate Case, the Company proposed to establish a remaining life for the facility of 12 years beginning January 1, 2016.The 12-year life corresponds with the facility's current FERC operating license, which is set to expire on December 31, 2027. In this Petition, the Company proposed a remaining life of 11 years for the St. Croix Hydro facility, which reflects a 1-year passage-of-time adjustment from the remaining life contemplated in the 2015 Rate Case.

The Department concluded that Xcel's proposed remaining life extension for the St. Croix Hydro Production Plant, which is based on the facility's current FERC operating license, is reasonable. The Department also noted that the proposed remaining life is consistent with the life approved by the Wisconsin Public Service Commission for the other property at the St. Croix Hydro facility.

Angus Anson Units 2 & 3

The Angus Anson Steam Plant is located in Sioux Falls, South Dakota on the Big Sioux River. Units 2 and 3 are dual-fired combustion turbines each rated at 90 MW built to provide peaking generation. The units originally were placed in service in 1994. Unit 4, installed in 2005, is a combustion turbine rated at 147 MW and has a separate remaining life from Units 2 and 3.

In the 2015 remaining life petition, the Commission ordered the Company to set the remaining life at 10 years at the beginning of 2016 because these units were anticipated to last longer into the IRP period than the then-current remaining life proposed by the Company. The current remaining lives for the Angus Anson Units 2 and 3 as of January 1, 2017 are nine years.

The Company's 2015 IRP forecasted the Angus Anson Units operating through the end of the planning period (2030), and the Commission recently approved that IRP (with unrelated modifications). In this filing, the Company updated its latest capital forecast for these units to include the capital replacement of turbine vanes and blades, as well as the generator breaker. These investments are currently estimated to be approximately $25.5 million in capital expenditures and to occur between 2019 and 2022.

Xcel anticipates that the plants will be able to operate through the end of the IRP period and requested that the Commission extend the remaining lives for Angus Anson Units 2 and 3 by 5 years which would result in a 14-year remaining life as of January 1, 2017. The estimated depreciation expense impact of these changes to remaining lives results in an annual decrease in depreciation of approximately $0.8 million for both units combined.

The Department recognized that the Company's proposed life extension would result in a match between the unit's IRP and depreciation remaining lives. When a life extension is requested based on capital expenditure, the Department stated it typically prefers to wait until the capital additions are either imminent or completed to extend a unit's life. For example, in Docket No. E-015/D-14-318, Minnesota Power requested a life extension effective January 1, 2014 for its Laskin Energy Facility based on investments expected to go in-service in late 2015. The Department recommended that the Commission deny Minnesota Power's requested life extension, as ratepayers would receive no operational benefits associated with the project until its completion, nearly 2 years in the future.[1] The Commission concluded that

> *"Generally, life extensions from capital projects should be recognized close to or at the time the project is placed in service. Though work is underway on the Laskin project, it is not close enough to the project's completion date or in-service date to appropriately recognize that Laskin's service life has been extended."*[2]

The Department opposed the life extension because the investments required for Angus Anson Units 2 and 3 to achieve the proposed remaining life are not expected to start until 2019 are not expected to be completed until 2022. There will be no operational benefits from these planned investments for at least a few years. It is also possible that circumstances may change between now and then that would render the investments cost ineffective.

The Department also argued that waiting to extend the units' remaining life would result in a smoother pattern of depreciation expense. Extending the life in this filing would result in relatively lower depreciation expense now and relatively higher expense in the future.

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[1] See the Department's August 15, 2014 Comments, page 5, in Docket No. E-015/D-14-318.
[2] See the Commission's January 16, 2015 Order, page 5, in Docket No. E-015/D-14-318.

Based on these observations, the Department recommended that the Commission approve a remaining life of 9 years for Angus Anson Units 2 and 3, reflecting a 1-year passage-of-time adjustment.

Xcel responded that the Department does not appear to oppose a life extension for these units in principal but rather takes the position that any life extension should wait until referenced capital investments are closer to their expected spend dates of 2019-2022.

The Company agreed that extending the life of a unit may not be appropriate prior to the completion of a future capital project if that project were the sole reason for the requested extension. The Company stated this appears to be the case for the Commission denying Minnesota Power's request to extend the life of the Laskin Energy Center.

The Company argued that its circumstances differ from Minnesota Power's request because its primary reason for requesting a life extension is to align the remaining lives of Angus Anson 2 & 3 with its 2015 Integrated Resource Plan, which was approved by the Commission (with modifications unrelated to Angus Anson) on January 11, 2017. The resource plan included the continued operation of Angus Anson Units 2 & 3 through 2030 because the Company's Strategist modeling indicated that it was economic and beneficial for its customers as opposed to building new resources. The Company stated that because the resource plan has been finalized and approved by the Commission, it believes it is reasonable and appropriate to extend the lives of these units as part of this docket.

Blue Lake Units 1-4

Blue Lake is a six unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. Units 1-4 are rated at 45 MW each. The station is located in Shakopee, Minnesota along the Minnesota River. Units 1-4 were placed in service in 1974. The plant is primarily used for capacity accreditation, and lesser so for energy production during peak demand periods.

In the IRP, the Company stated that Blue Lake Units 1-4 would provide reserve capacity through 2023. There are no major capital additions planned for the facility. In the 2015 remaining life filing, the Company requested and the Commission approve an eight-year remaining life as of January 1, 2016 to allow recovery of an increased estimate of $2.7 million for cost of removal. This was based on the expectation that the units could continue to run with minimal capital expenditure through that period.

In 2016 the Company analyzed these units as part of a decommissioning study and determined that they would require substantial capital investment of approximately $12.5 million to sustain their operation. Additionally, the units are currently only run in order to perform the required tests of functionality. As a result, the Company has determined that it would not be economically viable to make the investments needed to maintain the units' functionality. With minimal investment, the Company expects it can continue to operate these units to mid-2019. For these reasons the Xcel has proposed an end of life of July 1, 2019.

The Company requested that the remaining life of 7 years for Blue Lake Units 1-4 be shortened by 4.5 years, to a 2.5-year remaining life as of January 1, 2017. The estimated depreciation expense impact of these changes to remaining lives results in an annual increase in depreciation of approximately $0.6 million for 2017.

The Department agreed with Xcel's proposal because the Company is projected to have capacity surpluses in 2019-2023 even with the loss of Blue Lake Units 1-4's capacity. The Department stated the units' early retirement does not raise any reliability concerns and there is no need for the Company to make the capital investments required to ensure that the units can provide reserve capacity through 2023. Based on this, the Department concluded that Xcel's proposal to reduce the remaining life of Blue Lake Units 1-4 from 7 years to 2.5 years is reasonable.

Granite City

The Granite City Peaking Plant is located in St. Cloud, Minnesota, and was originally built in 1969. The plant consists of four units that generate a total of 61 MW of electricity using natural gas and oil. The plant is only used minimally for production but in the past has been deemed an essential power source for the Sherco plant in the event of a system blackout.

In the 2015 Depreciation Docket, the Commission approved a remaining life extension for Granite City, from 3.3 years to 8 years as of January 1, 2016. The Department agreed that extending the remaining life, through the end of 2023, was consistent with the operational life assumed in the 2015 IRP. At the time, no capital expenditures were planned for Granite City, and the Department concluded that capital additions would likely not be needed for the units to achieve the life assumed in the 2015 IRP.

In 2016, the Company analyzed this plant and determined that it would require substantial capital investment of approximately $8.0 million to sustain its operation. The units are currently only run in order to perform the required tests of functionality and as a result it has been determined that it would not be economically viable to make the necessary investments needed to maintain the units' functionality.

Additionally, while Granite City was intended as a black start generator for the Sherco Steam facilities, analysis now indicates that these units no longer possess the capacity to restart in the event of a black out. The Granite City units are no longer necessary to perform the black-start function under the Company's Power System Restoration Plan. Should a black-start of the Sherco units be needed, other black-start generating resources identified in the Company's Power System Restoration plan will perform this function. The Company remains confident that the existing plan will satisfy any requirements the loss of the Granite City facility could result in.

The Company currently expects it can continue to operate these units to mid-2019 with minimal additional investment. Xcel has requested that the Commission shorten the remaining life for Granite City by 4.5 years, to a 2.5-year remaining life as of January 1, 2017. The estimated depreciation expense impact of these changes to remaining lives results in an annual increase in depreciation of approximately $0.3 million for 2017.

The Department agreed with Xcel's proposal because Granite City's 4 units provide only 52 MW of capacity and are run infrequently. Their early retirement, even combined with the early retirement of Blue Lake Units 1-4, will pose no reliability concerns. Further, Granite City is no longer capable of providing black-start capabilities to the Sherco Steam facilities as previously intended. Based on this, the Department concluded that Xcel's proposed change to the remaining life of Granite City to run through June 30, 2019 to be reasonable.

Courtenay Wind

Courtenay Wind is a 200 MW wind farm located in east-central North Dakota near Courtenay, North Dakota. The site comprises 100 wind turbines covering 25,000 acres of land owned by 60 landowners. The production site began operation in November 2016. The costs for Courtenay Wind are being recovered through the Renewable Energy Standard (RES) Rider.

Consistent with actions in the IRP and the RES Rider, the Company proposed the remaining life for Courtenay Wind be set to 25 years from its in-service date of November 2016. A 25-year life is consistent with the treatment of the Company's Grand Meadow Wind, Nobles Wind, Border Winds and Pleasant Valley Wind facilities. A 25-year life is also consistent with remaining life expectations stated by the manufacturer of the turbines being used at these facilities.

Based on the remaining life of 25 years as of the November 2016 in-service date, the remaining life as of January 1, 2017 is 24.8 years. With this remaining life, along with the net salvage rate of negative 8.5 percent as discussed below, the Company has calculated 2017 depreciation for Courtenay Wind of approximately $12.5 million.

The Department agreed with Xcel's proposed life and stated that the life is consistent with the life proposed in the 2015 rate case, consistent with the lives of the Company's other wind facilities, and consistent with industry standards.

New Net Salvage Rate

Courtenay Wind

In the 2015 remaining life filing, the Company submitted its five-year study for the net salvage rates for its electric production facilities and its gas production and storage facilities. The net salvage rates approved by the Commission have been incorporated into this filing. At this time there is only one new net salvage rate and that is for the Courtenay Wind facility.

The Company stated that although it cannot currently determine with certainty when or under what conditions Courtenay Wind will be dismantled or demolished for final retirement, it must provide sufficient funding for these events. This will allow the Company to recover the cost of the removal of towers, turbines, concrete footings, transformers and other accessory equipment necessary to return the land to usable green space as they expect to lease land for the majority of these large wind energy conversion systems.

The Company proposed net salvage rate of negative 8.5 percent for Courtenay Wind. This net salvage rate is the same rate currently approved for Pleasant Valley Wind and Border Winds, and similar to the negative 8.7 percent net salvage rate that is currently approved for both the Grand Meadow and Nobles Wind Farms. The previously approved net salvage rates for other wind facilities were used as a guideline until a site-specific study can be completed for these facilities.

The construction and equipment for Courtenay Wind are similar enough to Pleasant Valley, Border Winds, Grand Meadow and Nobles Wind that the Company is confident that the net salvage rates for this new facility will be comparable. For this reason, and to be consistent with its proposal in the 2015 rate case (i.e. the MYRP for 2016 through 2019), the Company is requesting that the initial net salvage rate for Courtenay Wind be set at negative 8.5 percent.

The Department agreed with Xcel's proposed salvage rate and stated that the salvage rate is consistent with the salvage rate proposed in the 2015 rate case, consistent with the salvage rate of the Company's other wind facilities, and consistent with industry standards.

Amortization of Regulatory Assets for Theoretical Reserve Surplus

The Company is requesting that the Commission approve certain amortization rates for the unwinding of regulatory assets that were created by previous Commission Orders to address the Company's theoretical reserve surplus. Xcel is required to seek Commission approval of these rates in order to comply with the FERC accounting requirements.

Xcel Position

Xcel stated that approval of the amortization rates will not change the approved depreciation rates or the amount of expense that is calculated for rate making. In other words, there is no rate or revenue impact associated with this request. Xcel discusses the background and basis for its request in greater detail below.

1. Theoretical Reserve

A theoretical reserve is calculated by determining what the depreciation reserve would be at a point in time, if current information and assumptions about the life, salvage and cost of removal had been known since the beginning of each asset's life. In the 2012 Transmission, Distribution and General Depreciation Study (2012 TD&G Study), Docket No. E002/D-12-858, the theoretical reserve was lower than the actual book depreciation reserve, resulting in a theoretical reserve surplus. This filing presents a total Company view of the theoretical reserve surplus of $311.3 million.

To realign the actual depreciation reserve with the theoretical reserve, the future depreciation expense is reduced systematically by a portion of the surplus. Typically this is done over the average remaining life of the assets. However, the Commission can select different periods over which the theoretical reserve surplus would decrease future depreciation. The Commission Orders defining these periods are discussed below.

2. Previous Commission Orders

In its 2013 test year Minnesota electric rate case (2012 Rate Case), Docket No. E002/GR-12-961, the Commission required the Company to reduce depreciation expense by the Minnesota jurisdictional amount of the theoretical reserve surplus spread over eight years. The Minnesota jurisdictional amount of the theoretical reserve surplus was $261.2 million. Spreading this amount over eight years reduced the 2013 depreciation expense by $32.7 million. This negative depreciation expense was referred to as the amortization of the theoretical reserve surplus.

In its 2014 test year Minnesota electric rate case (2013 Rate Case), Docket No. E002/GR-13-868, the Commission required the Company to reduce depreciation expense in 2014 through 2016 by the remaining amount of the Minnesota jurisdictional amount of the theoretical reserve surplus using a declining pattern of 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016. The following table shows the resulting reduction to depreciation expense and the remaining theoretical reserve surplus at the end of each year.

Table 2: Amortization of Theoretical Reserve Surplus

Year	Reduction to Depreciation Expense	Remaining Theoretical Reserve Surplus
2013	(32,661,407)	(228,576,937)
2014	(114,288,468)	(114,288,469)
2015	(68,573,080)	(45,715,388)
2016	(45,715,388)	

3. FERC Accounting Requirements

As stated above, the reduction to depreciation expense for the amortization of the theoretical reserve surplus was done on a pattern that was authorized by the Commission. However, it was not done through the modification of the depreciation rate. Unwinding the theoretical reserve surplus over the average remaining life of the assets effectively modifies the average service life depreciation rate downward to account for this reduction in depreciation expense over the remaining life. In other words, if the Commission had authorized an average remaining life depreciation rate rather than an average service life rate, the theoretical reserve surplus would have been amortized over the remaining lives through a depreciation rate.

The Commission decided that the remaining lives were too long to reduce the future depreciation and chose a period that matched better with providing the depreciation reductions to those customers that contributed to the surplus. The 2012 Rate Case Order[3] provides the following insight from the Commission:

> *The Commission concurs that a five-year amortization period is too short, giving insufficient consideration to rate stability. But the Commission also finds that amortizing the surplus over the life of the plant would give insufficient consideration to issues of rate shock mitigation and intergenerational equity. While the ALJ suggested a 15-year amortization period, the Commission favors a period of roughly half that duration. Balancing the competing considerations, the Commission will direct Xcel to amortize the depreciation reserve surplus for its transmission, distribution, and general plant accounts over eight years.*

In determining depreciation expense and accumulated depreciation for the calculation of revenue requirements in Minnesota, the Company has included the amortization of the theoretical reserve surplus as a reduction to depreciation expense. In turn, the reduction in depreciation expense causes the accumulated depreciation to grow slower and thus net plant decreases slower. While this is proper rate making, the FERC will not allow the amortization of the theoretical reserve surplus, or negative depreciation expense, to be recognized as accumulated depreciation unless the reduction was done through a depreciation rate over the average remaining life. Only depreciation reductions handled through depreciation rate changes are allowed by the FERC to be recognized to accumulated depreciation on the Company's financials.

If amortizations use a method different than the average remaining life, the FERC requires recognition of negative depreciation expense as negative amortization that in turn sets up a regulatory asset. The Company has used the prescribed accounting for the amortization of the theoretical reserve surplus. Specifically, Xcel reduced expense through FERC Account 407.4 Regulatory Credits and increased FERC Account 182.3 Other Regulatory Assets. To align this accounting with Minnesota rate making, the regulatory assets are included in accumulated depreciation and the regulatory credit was included in depreciation expense.

As of December 31, 2016, all the negative depreciation expense has been recognized and the regulatory asset balance equals $261.2 million. Because part of the accumulated depreciation is sitting in a regulatory asset, the Company now needs to unwind the regulatory asset over the average remaining lives, which effectively moves the regulatory asset to the accumulated depreciation. Because this unwinding simply shifts the regulatory asset to accumulated depreciation, it is both revenue and rate-neutral.

4. Request for Amortization Rates for Regulatory Asset

As discussed above, to "unwind" a regulatory asset, the Company needs approved amortization rates from the Commission that set up the unwinding of regulatory asset. The Company is requesting the Commission approve the amortization rates as presented in Xcel's Attachment G for this unwinding.

[3] See Docket No. E-002/GR-12-961, Order dated September 3, 2013.

The approval of these amortization rates does not change the approved depreciation rates, nor does it change the amount of expense that is calculated for rate making. The amortization expense that will be recognized in 2017, using these amortization rates will simply show an expense in FERC Account 407.3 Regulatory Debits and at the same time FERC Account 403 Depreciation Expense will be reduced.

The net effect on total depreciation expense in the revenue requirement (amortization expense is collapsed into depreciation expense for rate making) is zero. An example of the regulatory view of this overall transaction and the FERC view, which is used for financial accounting, is included in Xcel's Attachment G as well.

Department Position

The Department recognized that as of December 31, 2016, Xcel has fully amortized the theoretical surplus as ordered in the 2012 and 2013 Rate Cases, and now has a regulatory asset of $261.2 million on its balance sheet in its FERC financial reports (FERC Form 1, etc.) According to the Company, the FERC will not allow the Company to begin unwinding (amortizing and expensing) this asset unless and until the Commission approves amortization rates for the asset.

The Department stated that Xcel made this same proposal in its most recent general rate case, Docket No. E002/GR-15-826. However, neither the Settlement nor the Commission's final Order addressed this proposal.

Based on the Company's explanation, the Department stated it understands that if the Commission approves Xcel's proposed amortization rates, the Company's accounting for depreciation expense and amortization expense will essentially be a three-step process.

First, the Company will record depreciation expense using Commission-approved depreciation rates with the following journal entry:

Dr: FERC Acct. 403 Depreciation Expense $XXX,XXX
Cr: FERC Acct. 108 Accumulated Depreciation $XXX,XXX

Second, the Company will record the amortization expense associated with its theoretical surplus using its proposed amortization rates in Attachment G to its Petition:

Dr: FERC Acct. 407.3 Regulatory Debit $YYY,YYY
Cr: FERC Acct. 182.3 Other Regulatory Assets $YYY,YYY

Third, in order to keep total depreciation and amortization expense equal to the amount of depreciation expense calculated using Commission-approved depreciation rates, Xcel will record a negative adjustment to depreciation expense exactly equal to the amortization expense recorded in FERC Account 407.3 shown in the second journal entry above:

Dr: FERC Acct. 108 Accumulated Depreciation $YYY,YYY
Cr: FERC Acct. 403 Depreciation Expense $YYY,YYY

As shown in Attachment G to the Company's Petition, the $261.2 million regulatory asset is allocated across its electric TD&G and common plant accounts, and will be amortized at the account level. The remaining lives shown in Attachment G over which Xcel proposes to amortize the regulatory asset were first calculated in Docket No. E,G-002/D-12-858.[4] In that Docket, Xcel initially proposed to switch from an average service life depreciation method to a remaining life method, and thus developed remaining life estimates for all of its plant accounts.[5] Xcel has adjusted the remaining lives calculated in that Docket for the passage of 5 years, and for any account with a remaining life of less than 5 years as of the beginning of 2017, Xcel has proposed to use a remaining life of 5 years.

While remaining lives for specific plant accounts change based on plant additions, retirements, changes in estimates, etc., if approved, the proposed amortization rates will not be recalculated annually using updated remaining lives. Rather, the amortization rates will remain fixed until the regulatory asset is fully amortized.

2. Department Analysis

In a related filing with the Public Service Commission of Wisconsin,[6] Xcel identified a 2011 FERC Order in a Florida Power Corporation (FPC) case that also pertained to the amortization of a theoretical reserve surplus over a time period other than the remaining lives of the affected plant accounts.[7] After reviewing that FPC case, the Department agrees that for purposes of FERC reporting, Xcel was required to account for the amortization of this theoretical reserve surplus as a regulatory asset, rather than as a direct adjustment to depreciation expense and accumulated depreciation. FPC, however, has not yet begun to unwind its regulatory asset, and the Department was unable to find any other similar FERC cases.[8]

The Department concluded that Xcel's accounting treatment of the theoretical reserve surplus amortization appropriately implements the Commission's Orders in the 2012 and 2013 Rate Cases in a manner consistent with FERC's accounting rules, and that the Company's request for approval of its proposed amortization rates is reasonable. However, the Department noted that its recommendation is based in part on Xcel's explanation that the proposed treatment will have no effect on the Company's revenue requirement. If approved by the Commission, the Company should be prepared to demonstrate in future rate case and rider proceedings that there are no cost impacts to ratepayers due to Xcel's accounting treatment of its theoretical reserve surplus amortization

[4] See Department Attachment 4.
[5] Xcel subsequently withdrew its request to switch to a remaining life method.
[6] See Northern States Power Company Wisconsin's January 20, 2014 Request for Deferred Accounting Treatment for Certain Reductions in Interchange Agreement Billings From Norther States Power Company, a Minnesota corporation in Docket No. 4220-GF-124.
[7] Florida Power Corp., 136 FERC ¶ 61,033 (2011), reh'g denied 137 FERC ¶ 61,150 (2011).
[8] See Department Attachment No 5.

Removal Update

The Commission's Order for the Company's 2015 remaining life filing required Xcel to continue to provide "updates on removal costs for the Minnesota Valley plant, Key City plant, and Black Dog Units 3 and 4." Also the updates should include any impact on the depreciation reserve as well as any final true-ups necessary. Xcel provided a 2017 update on these removal activities.

The OAG reviewed the update and expressed concern about the fluctuation of removal cost estimates and the reallocation of depreciation reserves that is used to address cost estimate increases, because of the intergenerational inequity that would arise from the Company collecting depreciation expense from ratepayers for facilities no longer in service which no longer provide any ratepayer benefits. Additionally, there are significant issues with the Company's removal cost update in the current filing.

1. Electric Utility –Steam Production: Black Dog Units 3 and 4

Black Dog Units 3 and 4 were officially retired from service in April 2015. These two units were coal-burning steam production units. Their removal from service ends the coal-fired production of electricity at Black Dog after more than 60 years.

As of January 1, 2017 approximately $20.6 million of dismantling costs have been incurred, and the Company estimates it is approximately 35 percent complete with the overall dismantling work. The turbines, generators and plant equipment have been removed, and the boiler removal is currently in process. The coal yard removal has been started, but is not yet complete. Additional activities that still need to take place include the removal of the Units 3 and 4 coal stacks and precipitators. There is also a portion of the facility that is necessary for the continued operation of Units 5 and 6. It is anticipated that these shared portions of the generating facility will not be able to be removed until the cessation of all Black Dog location operations.

As costs of removal are incurred at the Black Dog plant, the costs will be treated as a debit to the depreciation reserve, and the reserve balance will be reduced. At final removal of the plant assets, if there is reserve in excess of the plant balance, the Company plans to transfer this reserve to the remaining production accounts.

Over the life of the Black Dog units, the Company collected approximately $30.9 million for general dismantling activities. An additional $33.2 million for the coal yard remediation is being collected over 15 years for a total of $64 million in estimated total project cost. The Company continues to believe that these removal cost estimates are reasonable.

OAG Position

The OAG believes the depreciation reserve for Black Dog Units 3 &4 may be insufficient to cover the Company's projected removal costs. The OAG stated that the Company's current projection for general dismantling work is approximately $42.6 million with an additional $25.4 million for coal yard remediation, for a total of approximately $68 million in removal costs for

Black Dog Units 3 and 4, as summarized in the following table.

Xcel Projection of Removal Costs for Black Dog Units 3 & 4

	Total Projection
Characterization / Temporary Services	$87,735
Worker Access	$0
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	$176,160
Asbestos Remediation	$190,424
Equipment Removal	$8,567,422
Boiler(s)	$15,606,765
Structures Demolition	$7,200,000
Backfill / Grade / Landscaping / Well Closure	$0
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds	$0
Utility Management / Oversight	$7,071,360
Demolition Contractor Management / Supervisory / Safety Staff	$0
Security	$0
Property taxes	$0
Shared Heavy Equipment / Operating Engineers	$0
Small Tool Allowance	$0
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)	$0
Permits	$0
Demolition Contractors Insurance	$0
Demolition Contractors Fee	$0
Contingency	$5,578,506
Scrap Credit	($1,883,516)
Subtotal – General Dismantling Costs	**$42,594,855**
Coal Yard	$25,444,819
Grand Total	**$68,039,674**

The OAG observed the Company's current projection of removal costs exceeds the depreciation reserve balance by approximately $4 million. The Company stated that it intends to use depreciation reserve reallocations to address shortfalls.[9] The OAG expressed that it has the same intergenerational equity concerns that exist with any proposed reserve reallocation such as the reallocations proposed in the Company's previous remaining lives petition.

The OAG also compared the Company's current projection of general dismantling costs of $42 million to the cost estimates provided in the Company's most recent net salvage rate study. After allocating the Minnesota portion and adjusting the 2014 cost estimate to 2017 dollars, the OAG estimated a difference of $9.3 million between the cost estimate in the Company's last net salvage rate study and the Company's current projection. Additionally, although the Company's coal yard remediation work is projected to total $25,444,819, the expected total collection of $33,200,000 to cover this cost leaves only $7.7 million to cover any other future cost increases for coal yard remediation work or other general dismantling costs.

The OAG recommended that the Commission require the Company to clarify whether, based on its current projection, the depreciation reserve balance will be sufficient to cover all general dismantling costs and coal yard remediation costs, and explain why its current projection is

[9] See OAG Information Request No. 3 (Attachment B), OAG filing August 18, 2017 in this Docket.

higher than the cost estimate provided in its most recent net salvage rate study, even though the cost estimate included a contingency amount established using industry accepted methods, to account for unforeseeable future events.

Furthermore, since the Company transferred $3.2 million of depreciation reserve out of Black Dog Units 3 and 4 to the Minnesota Valley plant in its previous remaining lives petition, the Commission should require that going forward, the Company expense any removal costs that exceed the depreciation reserve balance and that no additional depreciation reserve balance is reallocated to fund any reserve shortfalls for closed plants.[10]

Xcel responded to the OAG's concerns about the Company's ability to dismantle the Black Dog steam units for the amount collected based on the 2015 TLG cost estimate, citing an estimated $3.93 million potential deficiency based on analysis provided in their comments. The OAG expressed concerns around the comparability of the data provided in the TLG cost studies and the Company's internal records. The Company stated that while it believes that TLG uses robust and accurate information to create their cost estimates, those estimates are principally intended to be viewed in total, as the specific details have the potential to change depending on the actual dismantling plan enacted. For this reason, the Company believes that any comparison to the study should occur at the total—rather than line-item—level.

The Company stated it believes that the final cost to dismantle the Black Dog facility will be reasonably close to the estimate approved in the 2015 remaining life filing. Given the long duration of this dismantling effort, the Company believes it would be premature to signal any potential deficit in funds for the project. Additionally, based on the amounts presented in the OAG's comments, the potential deficiency is approximately 6.1% of the total funds collected, which is hardly unreasonable considering the magnitude of the project and the age of the plant being dismantled.

2. Electric Utility –Steam Production: Minnesota Valley

The Minnesota Valley Plant is a former steam production facility located in Granite Falls, Minnesota along the Minnesota River. Minnesota Valley last burned coal in 2004, and the air permit was formally retired in 2009. The plant is no longer in operation.

As of January 1, 2017, the Company forecasted the coal yard removal and remediation to occur between 2018 and 2020, with the full site demolition date to follow. The completion of demolition is currently expected to be in 2023. As costs of removal are incurred at the Minnesota Valley Plant, the costs will be treated as a debit to the depreciation reserve, and the reserve

[10] The recommendation to expense the removal costs at issue is the result of the unique and specific facts in this docket. Because of those unique and specific facts, including the fact that the OAG raised concerns about moving depreciation expense between different facilities in Xcel's last depreciation filing, expensing removal costs in this instance is a more appropriate accounting treatment than reserve reallocation. It would prevent intergenerational inequity and provide the Company with incentives to keep costs low. This recommendation does not, however, extend to all removal costs, and does not dictate ratemaking treatment for future removal costs in other instances.

balance will be reduced. At final removal of the plant assets, if there is reserve in excess of the plant balance, the Company plans to transfer the reserve to other steam production accounts.

In sum, while the dam removal efforts have been completed much of the remediation process still needs to be completed. The Company will continue to inform the Commission of the forecasted removal activities, and will provide updates through the annual depreciation filings as the work is completed.

No other party commented on Xcel's removal update pertaining to the Minnesota Valley Plant.

3. Electric Utility –Other Production: Key City

The Key City Peaking Plant is located in Mankato, Minnesota, adjacent to Xcel Energy's Wilmarth Power Plant. The Key City plant had four units that generated a total of 64 MW of electricity using natural gas and oil as fuel. The plant became operational in 1970 and reached its end of life at the end of 2012.

Xcel stated that the Key City units are similar enough to the units currently in production at Granite City as to allow them to be used as a source of spare parts. Given this unique situation, the Company currently intends to maintain the Key City facility in a dormant state to support continued operations of Granite City facility up to the date that Granite City is retired. Per this remaining lives filing, that would allow for initial dismantling activities no sooner than mid-2019.

As costs of removal are incurred at the Key City plant, the costs will be treated as a debit to the depreciation reserve, and the reserve balance will be reduced. At final removal of the plant assets, if there is reserve in excess of the plant balance, we plan to transfer this reserve to the remaining production accounts.

OAG Position

The OAG requested more information from the Company about what parts have been taken from the Key City facility for use in the Granite City facility, and the Company's plans for transferring parts from Key City to Granite City. The Company responded that it had not yet transferred any parts and that it did not have any forecast of which parts would need to be transferred.

The OAG also asked the Company to explain the value of maintaining Key City in a dormant state where there would be maintenance costs and possible year-over-year increases to the dismantling costs, as compared to the market cost of parts that would have to be purchased by the Company if Key City is dismantled.

Because the net salvage rate study cost estimates do not include any post-shutdown "dormancy" costs"[11] and "does not account for an extended period of time between final shutdown of the unit(s) and onset of the dismantling program,"[12] these costs have not been built into the depreciation rates, nor reflected in the depreciation reserve balance. The OAG argued it is important for the Company to justify to the Commission why it is more economical to keep the Key City facility in a dormant state rather than dismantle it.

Given the fact that the Company's net salvage rate study cost estimates include a contingent cost for unforeseeable future events, it is reasonable to assume that dismantling costs will increase as dismantling work is either delayed or stretched out over long periods of time. This increases the potential for depreciation reserve shortfalls and the risk of intergenerational inequities should the Company continue to reallocate depreciation reserves. Therefore, the Company should provide a detailed analysis on the financial benefits to ratepayers to justify its decision to hold the Key City facility in a dormant state for over four years[13] before a projected dismantling start date in mid-2019. Unless the Company can demonstrate that delay will provide a clear financial benefit to ratepayers, the dismantling work for Key City should not be delayed.

Xcel Response

Xcel responded that the additional cost to maintain the Key City facility is small in comparison to the costs that could be incurred by a component failure at Granite City. There is no increase in staffing cost because the Wilmarth operators perform minimal upkeep required for the Key City plant. Additional costs for maintaining the dormant facility are estimated at $1,000/month. With respect to dismantling costs, using the 2% inflation assumption proposed in the OAG's comments in connection with the Black Dog removal, the $4.1 million estimate provided by TLG in 2014 dollars would amount to $4.5 million in 2019 dollars. This represents a $100,000 increase from today's 2017 escalated costs of $4.4 million.

The Company believes that the additional costs of maintaining the plant in a dormant state and the potential increase in the dismantling cost estimate due to inflation are out-weighed by the benefit of having a source of readily available spare parts for Granite City that could be otherwise difficult to procure.

Both the Key City and Granite City facilities are GE Frame 5 units and are within the same vintage – 1970. Key City has the potential to provide Granite City with the majority of its existing parts. In fact, the only major component that would not be interchangeable between the units is the control system. Xcel believes it is reasonable to assume that Granite City may eventually need these components because it has become difficult to find replacement parts for generating units of that vintage and because Granite City does not have spare parts available on site for many components.

[11] In the Matter of the Petition of Northern States Power Company for Approval of the 2015 Review of Remaining Lives, MPUC Docket No. E/G002/D-15-46, PETITION at Attachment I, Page 33 (May 18, 2015).
[12] In the Matter of the Petition of Northern States Power Company for Approval of the 2015 Review of Remaining Lives, MPUC Docket No. E/G002/D-15-46, PETITION at Attachment I, Page 20 (May 18, 2015).
[13] Plant shutdown was March 31, 2015.

The potential risks with earlier dismantling of Key City, and losing the ability to use the facility as a source of spare parts include the difficulty of finding spare parts for sale, the potential cost of refurbishing and/ or rebuilding those spare parts as needed, and the potential for an extended outage of one or more Granite City units while any critical spare parts are found and sent for refurbishment. The Company estimated that the units could be down for eight or more months while attempting to find and refurbish components that would have otherwise taken one month to transfer and install given the availability of the Key City components. While the Company does not have any specific plans or projections as to what parts may be required, it views the availability of the Key City components as worthwhile insurance against any number of potential failures at Granite City.

The Company stated it does not have specific plans to use the Key City components, but does see the potential risks avoided as more than offsetting the actual costs incurred to maintain the facility and the potential increase in dismantling costs due to delaying the dismantling activities.

Align Actual and Projected Costs to Net Salvage Rate Study

The OAG stated that in this proceeding, the Company provided a summary update for Black Dog Units 3 and 4. Actual removal costs of $20.6 million had been incurred as of January 1, 2017, with a total depreciation reserve balance of $30.9 million available to cover general dismantling costs. The Company also described additional dismantling work that was in-progress or projected to occur. Some of the in-progress work the Company described included coal yard remediation, for which the Company stated that it is currently collecting an additional $33.2 million of depreciation reserve.

The OAG requested additional details about the actual removal costs incurred for Black Dog Units 3 and 4 so that it could compare the actual costs incurred with the cost estimates provided in the Company's most recent net salvage rate study completed by TLG Services, Inc. ("TLG").5 Additionally, because the Company stated that only 35% of the dismantling work had been completed, the OAG asked the Company to provide its projected costs for the dismantling work that had yet to be incurred.

The Company explained in its response that its "ability to align its costs with the TLG study categories is limited" because "the Company does not maintain its removal records using the same categorizations as the tables TLG Services provides with their study." Further, the Company explained that the estimated costs in the study used an allocation for some costs (e.g. estimated asbestos removal costs were allocated to different pieces of equipment) whereas the actual costs, when incurred, would be directly assigned.

The OAG stated that the problem with Xcel not using the same categories is that it will make it harder to track how actual removal costs compare to the cost estimates in the Company's net salvage rate study. It also calls into question the Company's ability to use the cost estimates to inform its on-site dismantling plan and manage the removal costs that are actually incurred. The Company has stated that it "does not manage against the cost estimates provided TLG services when performing removal activities as this is not the intended purpose of the study." While it is understood that the TLG study is not intended to replace the on-site dismantling plan, the OAG argued that there is a relationship between the TLG cost estimates, the net salvage value which uses these cost estimates to set the depreciation rate, and the resulting depreciation reserve that is collected from ratepayers to cover actual removal costs.

The OAG pointed out that the net salvage rate study performed by TLG states that the cost estimates are established using a site-specific inventory of materials to be removed, upon which cost factors are applied to the corresponding inventory quantities. There are two types of cost factors that dismantling work fall under: activity-dependent cost factors that are “estimated using item quantities developed from plant drawings and inventory documents” and period-dependent cost factors that are “developed to determine the total dismantling program schedule.”

Given that TLG conducted “site walk-downs (including discussions with the Operations & Maintenance staff), station-provided equipment databases, and plant drawings” and have worked with the Company in its approach to develop the cost estimates, the OAG stated it is reasonable to expect that the projected and actual removal costs incurred should be comparable to the TLG study. While there may be some minor variances in the comparability of these amounts due to the time value of money, the method used to track actual and projected removal costs should be comparable with the method used to develop the cost estimates in its net salvage rate study. This is important because the cost estimates in the net salvage rate study are used to set depreciation rates, in which depreciation reserve is collected to cover removal costs.

The Commission should require that the Company further explain the current process it uses to determine the reasonableness of actual removal costs incurred, and how it manages its dismantling activities to ensure that they are efficient and economical in order to keep removal costs low. Furthermore, the Commission should require the Company to develop a process to compare actual and projected removal costs with the cost categories and cost estimates shown in its net salvage rate study, and provide a revised update on removal costs for the Minnesota Valley plant, the Key City plant, and Black Dog Units 3 and 4 that shows details regarding the actual and projected costs and the impact on the depreciation reserve balances.

Xcel Response

Xcel responded that the Company does not manage performance against the cost estimates provided by TLG services when performing removal activities as this is not the intended purpose of the study. The study makes this clear in its Introduction:

> *“The objective of this dismantling cost study prepared by TLG Services is to present an estimate of the costs to dismantle Xcel Energy’s fossil-fueled and wind farm generating electrical generating facilities, plus their gas production and storage facilities, in Minnesota and South Dakota. This study is not intended to be a dismantling plan for each of the stations, but a cost estimate prepared to support current financial planning for future dismantling.”*

The Company views the TLG study as a test for reasonableness in total in order to establish an appropriate net salvage percentage —not an item-by-item or plant-by-plant baseline or metric for measuring Xcel's performance. Detailed information was provided in the studies to aid in verifying the reasonableness of TLG's procedures and assumptions such as periods and unit cost factors applied in the study. The study is not presented to provide a basis for comparison to the actual line item costs of the dismantling project. The Company does not believe it is appropriate to perform a line-item level comparison between actual dismantling expenses and the tables provided by TLG. Indeed, there are material differences in terms of the detail provided by the TLG report compared to what is used in preparing internal forecasts for dismantling expenditures as well as the tracking of actual expenditures.

The Company proposes that the total cost estimate dollars from the TLG study be used as a basis for comparison against our actual total expenditures. The Company can then provide a description for the causes of material variances between the totals as necessary.

OAG Conclusion

It is important for the Commission to understand how reasonable the removal cost estimates in the Company's net salvage rate studies are because the depreciation rates are set using this information, and the resulting depreciation reserve is used to pay for those removal costs. The Company's summary, which describes the removal costs and depreciation reserves for the Minnesota Valley plant, Key City plant, and Black Dog Units 3 and 4, is insufficient to understand if there have been any cost increases to the estimates provided in the Company's most recent net salvage rate study, or any projected depreciation reserve shortfalls for any of the plants.

The Company has habitually reallocated depreciation reserves in the past to cover reserve shortfalls. The OAG argued that Company may lack an incentive to keep dismantling costs low for ratepayers by ensuring that dismantling activities are efficient and economical, because it knows that it can simply shift its depreciation reserves around to make up the difference.

The OAG recommended that the Commission require the Company to:

- Provide further details on its management of dismantling activities and costs, develop a method to compare its actual and projected removal costs to the cost estimates from its net salvage rate study, and provide a revised update for these costs and the depreciation reserve balance for all three facilities;
- Require that the Company fully explain any increases in removal costs for any of the three facilities; and
- Expense any removal costs that exceed the depreciation reserve balance.

Decision Alternatives

Housekeeping Issues

1) Require Xcel to file its next remaining life depreciation petition by February 19, 2018. (Xcel, Department) OR

2) Do not require Xcel to file its next remaining life depreciation petition by February 19, 2018 and determine that some other date is appropriate.

3) Require Xcel to continue to provide in future depreciation filings a comparison of depreciation remaining lives and resource planning lives for electric production with an explanation of any differences. (Xcel, Department) OR

4) Do not require Xcel to continue to provide in future depreciation filings a comparison of depreciation remaining lives and resource planning lives for electric production with an explanation of any differences.

5) Require Xcel to continue to provide in future depreciation filings a historical comparison of changes in remaining lives and net salvage rates. (Xcel, Department) OR

6) Do not require Xcel to continue to provide in future depreciation filings a historical comparison of changes in remaining lives and net salvage rates.

7) Require Xcel to continue to provide in future depreciation filings updates on removal costs for the Minnesota Valley Plant, Key City Plant and Black Dog Units 3 and 4, including the impact on depreciation reserves, and a final true-up when the retirement/removal is completed. (Xcel, Department, OAG) OR

8) Do not require Xcel to continue to provide in future depreciation filings updates on removal costs for the Minnesota Valley Plant, Key City Plant and Black Dog Units 3 and 4, including the impact on depreciation reserves, and a final true-up when the retirement/removal is completed.

Proposed Remaining Lives and Salvage Rates

9) Approve Xcel's proposed depreciation lives and salvage rates for its electric production, gas production, and gas storage facilities as the Company originally proposed in its initial filing. (Xcel)

10) Approve Xcel's proposed depreciation lives and salvage rates for its electric production, gas production, and gas storage facilities, except for the proposed remaining life for Angus Anson Units 2 and 3. (Department)

11) Approve a remaining life of 9 years for Angus Anson Units 2 and 3. (Department)

Additional Reporting Requirements

12) In future filings, require that the Company provide further details on its management of dismantling activities and costs, develop a method to compare its actual and projected removal costs to the cost estimates from its net salvage rate study, and provide a revised update for these costs and the depreciation reserve balance for Black Dog Units 3 & 4, Key City Plant and Minnesota Valley Plant. (Xcel, Department, OAG)

13) Require the Company to fully explain any increases in removal costs for Black Dog Units 3 & 4, Key City Plant and Minnesota Valley Plant, and that the Company expense any removal costs that exceed the depreciation reserve balance. (OAG would choose in addition to Decision Option 12)

14) Do not require the Company provide further details on its management of dismantling activities and costs, develop a method to compare its actual and projected removal costs to the cost estimates from its net salvage rate study, and provide a revised update for these costs and the depreciation reserve balance for Black Dog Units 3 & 4, Key City Plant and Minnesota Valley Plant.

15) Require that the Company provide a detailed analysis on the financial benefits to ratepayers to justify its decision to hold the Key City facility in a dormant state, or that it begin the dismantling work for Key City. (OAG)

16) Do not require the Company to provide a detailed analysis on the financial benefits to ratepayers to justify its decision to hold the Key City facility in a dormant state, or that it begin the dismantling work for Key City.

Recommendation

1, 3, 5, 7, 10, 11, 12, 16

Electric Utility
Steam Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/17
Allen S. King			
E311	Structures & Improvements	-8.2	20.5 yrs
E312	Boiler Plant Equipment	-8.2	20.5
E314	Turbogenerator Units	-8.2	20.5
E315	Accessory Electric Equipment	-8.2	20.5
E316	Miscellaneous Power Plant Equipment	-8.2	20.5
Red Wing			
E311	Structures & Improvements	-27.8	11.0 yrs
E312	Boiler Plant Equipment	-27.8	11.0
E314	Turbogenerator Units	-27.8	11.0
E315	Accessory Electric Equipment	-27.8	11.0
E316	Miscellaneous Power Plant Equipment	-27.8	11.0
Sherco Unit 1			
E311	Structures & Improvements	-15.2	9.0 yrs
E312	Boiler Plant Equipment	-15.2	9.0
E314	Turbogenerator Units	-15.2	9.0
E315	Accessory Electric Equipment	-15.2	9.0
E316	Miscellaneous Power Plant Equipment	-15.2	9.0
Sherco Unit 2			
E311	Structures & Improvements	-15.2	9.0 yrs
E312	Boiler Plant Equipment	-15.2	6.0
E314	Turbogenerator Units	-15.2	6.0
E315	Accessory Electric Equipment	-15.2	6.0
E316	Miscellaneous Power Plant Equipment	-15.2	6.0
Sherco Unit 3			
E311	Structures & Improvements	-5.4	18.0 yrs
E312	Boiler Plant Equipment	-5.4	18.0
E314	Turbogenerator Units	-5.4	18.0
E315	Accessory Electric Equipment	-5.4	18.0
E316	Miscellaneous Power Plant Equipment	-5.4	18.0
Wilmarth			
E311	Structures & Improvements	-26.8	11.0 yrs
E312	Boiler Plant Equipment	-26.8	11.0
E314	Turbogenerator Units	-26.8	11.0
E315	Accessory Electric Equipment	-26.8	11.0
E316	Miscellaneous Power Plant Equipment	-26.8	11.0

Electric Utility
Nuclear Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/17
Monticello			
E302	Franchises & Consents	0.0	13.8 yrs
E321	Structures & Improvements	0.0	13.8
E322	Reactor Plant Equipment	0.0	13.8
E323	Turbogenerator Units	0.0	13.8
E324	Accessory Electric Equipment	0.0	13.8
E325	Miscellaneous Power Plant Equipment	0.0	13.8
Monticello - Interim Storage Facility			
E321	Structures and Improvements	0.0	13.8 yrs
E322	Reactor Plant Equipment	0.0	13.8
Prairie Island Unit 1 & 2			
E302	Franchises & Consents	0.0	17.3 yrs
E321	Structures & Improvements	0.0	17.3
E322	Reactor Plant Equipment	0.0	17.3
E323	Turbogenerator Units	0.0	17.3
E324	Accessory Electric Equipment	0.0	17.3
E325	Miscellaneous Power Plant Equipment	0.0	17.3
Prairie Island - Interim Storage Facility			
E321	Structures and Improvements	0.0	17.3 yrs
E322	Reactor Plant Equipment	0.0	17.3

Electric Utility
Hydro Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/17
Hennepin Island			
E302	Franchises & Consents	0.0	17.2 yrs
E331	Structures & Improvements	-26.4	17.2
E332	Reservoirs, Dams & Waterways	-26.4	17.2
E333	Water Wheels, Turbines & Generators	-26.4	17.2
E334	Accessory Electric Equipment	-26.4	17.2
E335	Miscellaneous Power Plant Equipment	-26.4	17.2
St. Croix Falls			
E331	Structures & Improvements	-7.5	11 yrs
E332	Reservoirs, Dams & Waterways	-7.5	11
Upper Dam			
E332	Reservoirs, Dams & Waterways	-26.4	17.2 yrs
E335	Miscellaneous Power Plant Equipment	-26.4	17.2

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/17
Angus C. Anson Unit 2 & 3			
E341	Structures & Improvements	-6.5	18.4 yrs
E342	Fuel Holders, Producers & Accessories	-9.6	14.0
E344	Generators	-9.6	14.0
E345	Accessory Electric Equipment	-9.6	14.0
E346	Miscellaneous Power Plant Equipment	-9.6	14.0
Angus C. Anson Unit 4			
E341	Structures & Improvements	-6.5	18.4 yrs
E342	Fuel Holders, Producers & Accessories	-6.5	18.4
E344	Generators	-6.5	18.4
E345	Accessory Electric Equipment	-6.5	18.4
E346	Miscellaneous Power Plant Equipment	-6.5	18.4
Black Dog Unit 5			
E341	Structures & Improvements	-11.4	15.0 yrs
E342	Fuel Holders, Producers & Accessories	-11.4	15.0
E344	Generators	-11.4	15.0
E345	Accessory Electric Equipment	-11.4	15.0
E346	Miscellaneous Power Plant Equipment	-11.4	15.0
Blue Lake Units 1 thru 4			
E341	Structures & Improvements	-11.7	18.4 yrs
E342	Fuel Holders, Producers & Accessories	-22.9	2.5
E344	Generators	-22.9	2.5
E345	Accessory Electric Equipment	-22.9	2.5
E346	Miscellaneous Power Plant Equipment	-22.9	2.5
Blue Lake Units 7 & 8			
E341	Structures & Improvements	-11.7	18.4 yrs
E342	Fuel Holders, Producers & Accessories	-11.7	18.4
E344	Generators	-11.7	18.4
E345	Accessory Electric Equipment	-11.7	18.4
E346	Miscellaneous Power Plant Equipment	-11.7	18.4
Border Winds Project			
E340.1	Wind Rights	0.0	24.0 yrs
E341	Structures & Improvements	-8.5	24.0
E342	Fuel Holders, Producers & Accessories	-8.5	24.0
E344	Generators	-8.5	24.0
E345	Accessory Electric Equipment	-8.5	24.0
E346	Miscellaneous Power Plant Equipment	-8.5	24.0

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/17
Courtenay Winds Project			
E340.1	Wind Rights	0.0	24.9 yrs
E341	Structures & Improvements	-8.5	24.9
E342	Fuel Holders, Producers & Accessories	-8.5	24.9
E344	Generators	-8.5	24.9
E345	Accessory Electric Equipment	-8.5	24.9
E346	Miscellaneous Power Plant Equipment	-8.5	24.9
Grand Meadow Wind Project			
E340.1	Wind Rights	0.0	16.9 yrs
E341	Structures & Improvements	-11.1	16.9
E342	Fuel Holders, Producers & Accessories	-11.1	16.9
E344	Generators	-11.1	16.9
E345	Accessory Electric Equipment	-11.1	16.9
E346	Miscellaneous Power Plant Equipment	-11.1	16.9
Granite City			
E341	Structures & Improvements	-50.4	2.5 yrs
E342	Fuel Holders, Producers & Accessories	-50.4	2.5
E344	Generators	-50.4	2.5
E345	Accessory Electric Equipment	-50.4	2.5
E346	Miscellaneous Power Plant Equipment	-50.4	2.5
High Bridge			
E341	Structures & Improvements	-3.5	31.4 yrs
E342	Fuel Holders, Producers & Accessories	-3.5	31.4
E344	Generators	-3.5	31.4
E345	Accessory Electric Equipment	-3.5	31.4
E346	Miscellaneous Power Plant Equipment	-3.5	31.4
Inver Hills			
E341	Structures & Improvements	-18.3	10.0 yrs
E342	Fuel Holders, Producers & Accessories	-18.3	10.0
E344	Generators	-18.3	10.0
E345	Accessory Electric Equipment	-18.3	10.0
E346	Miscellaneous Power Plant Equipment	-18.3	10.0

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/17
Nobles Wind Project			
E340.1	Wind Rights	0.0	18.9 yrs
E341	Structures & Improvements	-6.0	18.9
E342	Fuel Holders, Producers & Accessories	-6.0	18.9
E344	Generators	-6.0	18.9
E345	Accessory Electric Equipment	-6.0	18.9
E346	Miscellaneous Power Plant Equipment	-6.0	18.9
Pleasant Valley Wind Project			
E340.1	Wind Rights	0.0	24.0 yrs
E341	Structures & Improvements	-8.5	24.0
E342	Fuel Holders, Producers & Accessories	-8.5	24.0
E344	Generators	-8.5	24.0
E345	Accessory Electric Equipment	-8.5	24.0
E346	Miscellaneous Power Plant Equipment	-8.5	24.0
Riverside			
E341	Structures & Improvements	-11.3	32.2 yrs
E342	Fuel Holders, Producers & Accessories	-11.3	32.2
E344	Generators	-11.3	32.2
E345	Accessory Electric Equipment	-11.3	32.2
E346	Miscellaneous Power Plant Equipment	-11.3	32.2
United Hospital			
E344	Generators	0.0	0.7 yrs
Wind-to-Battery System			
E348.1	Energy Storage Equipment	0.0	7.0 yrs

Gas Utility
Gas Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/17
Maplewood			
G305	Structures & Improvements	-93.7	13.0 yrs
G311	LP Gas Equipment	-93.7	13.0
G320	Other Equipment	-93.7	13.0
Sibley			
G305	Structures & Improvements	-79.5	13.0 yrs
G311	LP Gas Equipment	-79.5	13.0
G320	Other Equipment	-79.5	13.0
Wescott			
G305	Structures & Improvements	-19.2	13.0 yrs
G311	LP Gas Equipment	-19.2	13.0
G320	Other Equipment	-19.2	13.0

Gas Utility
Gas Storage

Account	Description	Net Salvage (%)	Remaining Life 01/01/16
Wescott			
G361	Structures & Improvements	-19.2	7.0 yrs
G362	Gas Holders	-19.2	7.0
G363	Purification Equipment	-19.2	7.0
G363.1	Liquefaction Equipment	-19.2	7.0
G363.2	Vaporizing Equipment	-19.2	11.0
G363.3	Compressor Equipment	-19.2	16.0
G363.4	Measuring & Regulating Equipment	-19.2	7.0
G363.5	Other Equipment	-19.2	7.0

Northern States Power Company
Theoretical Reserve Surplus Amortization
Regulatory View versus GAAP View

				Regulatory Asset Set-up					Regulatory Asset Flow-back			
		Proposed Amortization Rate for Regulatory Asset (GAAP)	Initial Theoretical Reserve (From 12-961)	2013	2014	2015	2016	Total Set-up	2017 Annual Amortization	Remaining Life	Total Amortization Expense	Regulatory Asset Balance at End of Remaining Life
Electric Intangible												
303	Computer Software - 5 year	20.00%	(365,054)	(45,632)	(159,711)	(95,827)	(63,884)	(365,054)	73,011	5.00	365,054	-
Transmission												
352	Structures & Improvements	2.10%	(3,566,139)	(445,767)	(1,560,186)	(936,111)	(624,074)	(3,566,139)	74,812	47.67	3,566,139	-
353	Station Equipment	2.52%	(65,644,975)	(8,205,622)	(28,719,677)	(17,231,806)	(11,487,871)	(65,644,975)	1,652,353	39.73	65,644,975	-
354	Towers & Fixtures	2.75%	(21,399,335)	(2,674,917)	(9,362,209)	(5,617,325)	(3,744,884)	(21,399,335)	589,527	36.30	21,399,335	-
355	Poles & Fixtures	2.04%	(33,316,127)	(4,164,516)	(14,575,805)	(8,745,483)	(5,830,322)	(33,316,127)	678,237	49.12	33,316,127	-
356	Overhead Conductor & Devices	2.12%	(23,571,692)	(2,946,461)	(10,312,615)	(6,187,569)	(4,125,046)	(23,571,692)	499,051	47.23	23,571,692	-
357	Underground Conduit	1.90%	(877,921)	(109,740)	(384,091)	(230,454)	(153,636)	(877,921)	16,698	52.58	877,921	-
358	Underground Conductor & Devices	2.45%	(1,221,219)	(152,652)	(534,283)	(320,570)	(213,713)	(1,221,219)	29,903	40.84	1,221,219	-
Distribution - Minnesota Only												
361	Structures & Improvements	2.78%	(1,486,783)	(185,848)	(650,468)	(390,281)	(260,187)	(1,486,783)	41,400	35.91	1,486,783	-
362	Station Equipment	2.71%	(13,222,426)	(1,652,803)	(5,784,811)	(3,470,887)	(2,313,924)	(13,222,426)	357,898	36.94	13,222,426	-
364	Poles, Towers & Fixtures	3.68%	(16,011,643)	(2,001,455)	(7,005,094)	(4,203,056)	(2,802,037)	(16,011,643)	589,987	27.14	16,011,643	-
365	Overhead Conductor & Devices	3.90%	(8,431,224)	(1,053,903)	(3,688,660)	(2,213,196)	(1,475,464)	(8,431,224)	328,984	25.63	8,431,224	-
366	Underground Conduit	2.98%	(5,961,886)	(745,236)	(2,608,325)	(1,564,995)	(1,043,330)	(5,961,886)	177,681	33.55	5,961,886	-
367	Underground Conductor & Devices	3.69%	(24,504,662)	(3,063,083)	(10,720,789)	(6,432,474)	(4,288,316)	(24,504,662)	904,691	27.09	24,504,662	-
368	Line Transformers	7.27%	(20,841,453)	(2,605,182)	(9,118,135)	(5,470,881)	(3,647,254)	(20,841,453)	1,514,920	13.76	20,841,453	-
368	Line Capacitors	17.37%	(851,214)	(106,402)	(372,406)	(223,444)	(148,962)	(851,214)	147,889	5.76	851,214	-
369	Services - Overhead	5.07%	(4,727,887)	(590,986)	(2,068,451)	(1,241,070)	(827,380)	(4,727,887)	239,543	19.74	4,727,887	-
369	Services - Underground	5.08%	(7,456,052)	(932,007)	(3,262,023)	(1,957,214)	(1,304,809)	(7,456,052)	378,790	19.68	7,456,052	-
370	Meters	20.00%	(4,171,233)	(521,404)	(1,824,915)	(1,094,949)	(729,966)	(4,171,233)	834,247	5.00	4,171,233	-
373	Street Light & Signal Systems	5.83%	(1,695,891)	(211,986)	(741,952)	(445,171)	(296,781)	(1,695,891)	98,879	17.15	1,695,891	-
Electric General												
390	Structures & Improvements	3.04%	(2,675,460)	(334,432)	(1,170,514)	(702,308)	(468,205)	(2,675,460)	81,457	32.84	2,675,460	-
391	Office Furniture & Equipment	12.90%	(434,962)	(54,370)	(190,296)	(114,178)	(76,118)	(434,962)	56,098	7.75	434,962	-
391	Network Equipment	20.00%	(136,967)	(17,121)	(59,923)	(35,954)	(23,969)	(136,967)	27,393	5.00	136,967	-
392	Transportation Equipment - Automobiles	20.00%	(4,680)	(585)	(2,047)	(1,228)	(819)	(4,680)	936	5.00	4,680	-
392	Transportation Equipment - Light Trucks	20.00%	(326,016)	(40,752)	(142,632)	(85,579)	(57,053)	(326,016)	65,203	5.00	326,016	-
392	Transportation Equipment - Trailers	12.96%	(57,655)	(7,207)	(25,224)	(15,134)	(10,090)	(57,655)	7,471	7.72	57,655	-
392	Transportation Equipment - Heavy Trucks	17.15%	(495,501)	(61,938)	(216,782)	(130,069)	(86,713)	(495,501)	85,000	5.83	495,501	-
393	Stores Equipment	12.47%	(22,553)	(2,819)	(9,867)	(5,920)	(3,947)	(22,553)	2,812	8.02	22,553	-
394	Tools, Shop & Garage Equipment	20.00%	(910,277)	(113,784)	(398,246)	(238,947)	(159,299)	(910,277)	182,055	5.00	910,277	-
395	Laboratory Equipment	20.00%	(97,850)	(12,231)	(42,809)	(25,685)	(17,124)	(97,850)	19,570	5.00	97,850	-
396	Power Operated Equipment	20.00%	(196,609)	(24,576)	(86,017)	(51,610)	(34,407)	(196,609)	39,322	5.00	196,609	-
397	Communication Equipment	20.00%	(458,204)	(57,276)	(200,465)	(120,279)	(80,185)	(458,204)	91,641	5.00	458,204	-
398	Miscellaneous Equipment	20.00%	(71,984)	(8,998)	(31,493)	(18,896)	(12,597)	(71,984)	14,397	5.00	71,984	-
Common Intangible												
303	Computer Software - 5 year	20.00%	979,323	122,415	428,454	257,072	171,381	979,323	(195,865)	5.00	(979,323)	-
303	Computer Software - 10 year	20.00%	6,942	868	3,037	1,822	1,215	6,942	(1,388)	5.00	(6,942)	-
Common General												
390	Structures & Improvements	2.55%	1,714,751	214,344	750,204	450,122	300,081	1,714,751	(43,752)	39.19	(1,714,751)	-
390	Structures & Improvements - Leasehold Improvements	20.00%	32,891	4,111	14,390	8,634	5,756	32,891	(6,578)	5.00	(32,891)	-
391	Office Furniture & Equipment	20.00%	477,484	52,252	212,616	127,570	85,046	477,484	(95,497)	5.00	(477,484)	-
391	Network Equipment	20.00%	429,668	53,708	187,980	112,788	75,192	429,668	(85,934)	5.00	(429,668)	-
392	Transportation Equipment - Automobiles	20.00%	3,732	542	1,595	957	638	3,732	(746)	5.00	(3,732)	-
392	Transportation Equipment - Light Trucks	20.00%	82,672	10,334	36,169	21,701	14,468	82,672	(16,534)	5.00	(82,672)	-
392	Transportation Equipment - Trailers	18.31%	12,799	1,600	5,600	3,360	2,240	12,799	(2,344)	5.46	(12,799)	-
392	Transportation Equipment - Heavy Trucks	20.00%	64,838	8,105	28,367	17,020	11,347	64,838	(12,968)	5.00	(64,838)	-
393	Stores Equipment	7.61%	32	4	14	8	6	32	(2)	13.15	(32)	-
394	Tools, Shop & Garage Equipment	19.49%	26,521	3,315	11,603	6,962	4,641	26,521	(5,170)	5.13	(26,521)	-
395	Laboratory Equipment	20.00%	1,034	129	452	271	181	1,034	(207)	5.00	(1,034)	-
396	Power Operated Equipment	20.00%	8,677	1,074	3,801	2,281	1,521	8,677	(1,735)	5.00	(8,677)	-
397	Communication Equipment	20.00%	115,549	14,444	50,553	30,332	20,221	115,549	(23,110)	5.00	(115,549)	-
398	Miscellaneous Equipment	20.00%	18,275	3,039	7,618	4,571	3,047	18,275	(3,655)	5.00	(18,275)	-
			(261,238,344)	(32,661,407)	(114,288,468)	(68,573,081)	(45,715,388)	(261,238,344)	9,406,370		261,238,344	-

Electric Transmission Structures & Improvements - FERC Account 352

46,878,153 Beginning Plant Balance @ January 1, 2012 (Total Company)
15,348,271 Beginning Accumulated Depreciation @ January 1, 2012 (Total Company)
4,778,777 Theoretical Reserve Difference @ January 1, 2012 (Total Company)
74.6245% MN Jurisdictional Allocator
1.47% Average Service Life Rate - Approved

47.67 Average Remaining Life in 2017
2.10% Proposed Amortization Rate for Regulatory Asset (GAAP) - Both Jurisdictions

	Regulatory View - MN Jurisdiction				GAAP View								
Year	ASL Depr Expense (MN Jurisdiction)	Theo Reserve Adj to Depreciation	Total Depreciation Expense	Accum Depr	ASL Depr Expense (MN Jurisdiction)	MN Jurisdiction Depr Expense Adjustment	Total Depreciation Expense	Accum Depr	Regulatory Asset Amortization (MN Jurisdiction)	Regulatory Asset Balance (MN Jurisdiction)	Total Depr & Amortization Expense Recognized	Accum Depr (Including Regulatory Asset Balances)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	
				11,968,020				11,968,020				11,968,020	-
2013	514,450	(445,767)	68,682	12,036,703	514,450		514,450	12,482,470	(445,767)	445,767	68,682	12,036,703	-
2014	514,450	(1,560,186)	(1,045,736)	10,990,967	514,450		514,450	12,996,920	(1,560,186)	2,005,953	(1,045,736)	10,990,967	-
2015	514,450	(936,111)	(421,662)	10,569,305	514,450		514,450	13,511,370	(936,111)	2,942,064	(421,662)	10,569,305	-
2016	514,450	(624,074)	(109,624)	10,459,681	514,450		514,450	14,025,820	(624,074)	3,566,139	(109,624)	10,459,681	-
2017	514,450	-	514,450	10,974,131	514,450	(74,812)	439,638	14,465,458	74,812	3,491,327	514,450	10,974,131	-
2018	514,450	-	514,450	11,488,581	514,450	(74,812)	439,638	14,905,096	74,812	3,416,515	514,450	11,488,581	-
2019	514,450	-	514,450	12,003,030	514,450	(74,812)	439,638	15,344,734	74,812	3,341,704	514,450	12,003,030	-
2020	514,450	-	514,450	12,517,480	514,450	(74,812)	439,638	15,784,372	74,812	3,266,892	514,450	12,517,480	-
2021	514,450	-	514,450	13,031,930	514,450	(74,812)	439,638	16,224,010	74,812	3,192,080	514,450	13,031,930	-
2022	514,450	-	514,450	13,546,380	514,450	(74,812)	439,638	16,663,649	74,812	3,117,269	514,450	13,546,380	-
2023	514,450	-	514,450	14,060,830	514,450	(74,812)	439,638	17,103,287	74,812	3,042,457	514,450	14,060,830	-
2024	514,450	-	514,450	14,575,279	514,450	(74,812)	439,638	17,542,925	74,812	2,967,645	514,450	14,575,279	-
2025	514,450	-	514,450	15,089,729	514,450	(74,812)	439,638	17,982,563	74,812	2,892,834	514,450	15,089,729	-
2026	514,450	-	514,450	15,604,179	514,450	(74,812)	439,638	18,422,201	74,812	2,818,022	514,450	15,604,179	-
2027	514,450	-	514,450	16,118,629	514,450	(74,812)	439,638	18,861,839	74,812	2,743,210	514,450	16,118,629	-
2028	514,450	-	514,450	16,633,079	514,450	(74,812)	439,638	19,301,477	74,812	2,668,399	514,450	16,633,079	-
2029	514,450	-	514,450	17,147,529	514,450	(74,812)	439,638	19,741,116	74,812	2,593,587	514,450	17,147,529	-
2030	514,450	-	514,450	17,661,978	514,450	(74,812)	439,638	20,180,754	74,812	2,518,775	514,450	17,661,978	-
2031	514,450	-	514,450	18,176,428	514,450	(74,812)	439,638	20,620,392	74,812	2,443,964	514,450	18,176,428	-
2032	514,450	-	514,450	18,690,878	514,450	(74,812)	439,638	21,060,030	74,812	2,369,152	514,450	18,690,878	-
2033	514,450	-	514,450	19,205,328	514,450	(74,812)	439,638	21,499,668	74,812	2,294,340	514,450	19,205,328	-
2034	514,450	-	514,450	19,719,778	514,450	(74,812)	439,638	21,939,306	74,812	2,219,529	514,450	19,719,778	-
2035	514,450	-	514,450	20,234,227	514,450	(74,812)	439,638	22,378,944	74,812	2,144,717	514,450	20,234,227	-
2036	514,450	-	514,450	20,748,677	514,450	(74,812)	439,638	22,818,583	74,812	2,069,905	514,450	20,748,677	-
2037	514,450	-	514,450	21,263,127	514,450	(74,812)	439,638	23,258,221	74,812	1,995,094	514,450	21,263,127	-
2038	514,450	-	514,450	21,777,577	514,450	(74,812)	439,638	23,697,859	74,812	1,920,282	514,450	21,777,577	-
2039	514,450	-	514,450	22,292,027	514,450	(74,812)	439,638	24,137,497	74,812	1,845,470	514,450	22,292,027	-
2040	514,450	-	514,450	22,806,476	514,450	(74,812)	439,638	24,577,135	74,812	1,770,659	514,450	22,806,476	-
2041	514,450	-	514,450	23,320,926	514,450	(74,812)	439,638	25,016,773	74,812	1,695,847	514,450	23,320,926	-
2042	514,450	-	514,450	23,835,376	514,450	(74,812)	439,638	25,456,411	74,812	1,621,035	514,450	23,835,376	-
2043	514,450	-	514,450	24,349,826	514,450	(74,812)	439,638	25,896,050	74,812	1,546,224	514,450	24,349,826	-
2044	514,450	-	514,450	24,864,276	514,450	(74,812)	439,638	26,335,688	74,812	1,471,412	514,450	24,864,276	-
2045	514,450	-	514,450	25,378,725	514,450	(74,812)	439,638	26,775,326	74,812	1,396,600	514,450	25,378,725	-
2046	514,450	-	514,450	25,893,175	514,450	(74,812)	439,638	27,214,964	74,812	1,321,789	514,450	25,893,175	-
2047	514,450	-	514,450	26,407,625	514,450	(74,812)	439,638	27,654,602	74,812	1,246,977	514,450	26,407,625	-
2048	514,450	-	514,450	26,922,075	514,450	(74,812)	439,638	28,094,240	74,812	1,172,165	514,450	26,922,075	-
2049	514,450	-	514,450	27,436,525	514,450	(74,812)	439,638	28,533,879	74,812	1,097,354	514,450	27,436,525	-
2050	514,450	-	514,450	27,950,975	514,450	(74,812)	439,638	28,973,517	74,812	1,022,542	514,450	27,950,975	-
2051	514,450	-	514,450	28,465,424	514,450	(74,812)	439,638	29,413,155	74,812	947,730	514,450	28,465,424	-
2052	514,450	-	514,450	28,979,874	514,450	(74,812)	439,638	29,852,793	74,812	872,919	514,450	28,979,874	-
2053	514,450	-	514,450	29,494,324	514,450	(74,812)	439,638	30,292,431	74,812	798,107	514,450	29,494,324	-
2054	514,450	-	514,450	30,008,774	514,450	(74,812)	439,638	30,732,069	74,812	723,296	514,450	30,008,774	-
2055	514,450	-	514,450	30,523,224	514,450	(74,812)	439,638	31,171,707	74,812	648,484	514,450	30,523,224	-
2056	514,450	-	514,450	31,037,673	514,450	(74,812)	439,638	31,611,346	74,812	573,672	514,450	31,037,673	-
2057	514,450	-	514,450	31,552,123	514,450	(74,812)	439,638	32,050,984	74,812	498,861	514,450	31,552,123	-
2058	514,450	-	514,450	32,066,573	514,450	(74,812)	439,638	32,490,622	74,812	424,049	514,450	32,066,573	-
2059	514,450	-	514,450	32,581,023	514,450	(74,812)	439,638	32,930,260	74,812	349,237	514,450	32,581,023	-
2060	514,450	-	514,450	33,095,473	514,450	(74,812)	439,638	33,369,898	74,812	274,426	514,450	33,095,473	-
2061	514,450	-	514,450	33,609,922	514,450	(74,812)	439,638	33,809,536	74,812	199,614	514,450	33,609,922	-
2062	514,450	-	514,450	34,124,372	514,450	(74,812)	439,638	34,249,174	74,812	124,802	514,450	34,124,372	-
2063	514,450	-	514,450	34,638,822	514,450	(74,812)	439,638	34,688,813	74,812	49,991	514,450	34,638,822	-
2064	343,765	-	343,765	**34,982,587**	343,765	(49,991)	293,774	**34,982,587**	49,991	-	343,765	**34,982,587**	-

Beginning Reserve	**11,968,020**
Remaining Life Depreciation	**445,430**
Remaining Life	**51.67**
Total Depreciation over Remaining Life	**23,014,567**
Total Reserve at End of Remaining Life	**34,982,587**