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August 22, 2008

Gloria Geiger  
Interim Director of Administration  
North Dakota Public Service Commission  
State Capitol  
600 East Boulevard  
Bismarck, ND 58505-0480

Re: In the Matter of the Application of Northern States Power Company, a  
Minnesota Corporation, for Authority to Increase Rates for Electric Service in  
North Dakota  
Case No. PU-07-776

Dear Ms. Geiger:

Enclosed are the original and ten copies of the Initial Brief of Northern States Power Company, a Minnesota corporation operating in North Dakota, in the above-entitled case. A copy of the Initial Brief has also been provided by email to [ndpsc@nd.gov](mailto:ndpsc@nd.gov).

Very truly yours,

A handwritten signature in black ink, appearing to read 'Megan J. Hertzler', written over a horizontal line.

Megan J. Hertzler  
Assistant General Counsel

Encls.

cc: Service List

**In the Matter of the Application by  
Northern States Power Company,  
a Minnesota corporation  
for Authority to Increase Rates for Electric Service in North Dakota  
Case No. PU-07-776**

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**STATE OF NORTH DAKOTA  
BEFORE THE  
PUBLIC SERVICE COMMISSION**

In the Matter of the Application by  
Northern States Power Company, a  
Minnesota Corporation, for Authority to  
Increase Rates for Electric Service in  
North Dakota

Case No. PU-07-776

**INITIAL BRIEF OF XCEL ENERGY**

August 22, 2008

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STATE OF NORTH DAKOTA  
BEFORE THE  
PUBLIC SERVICE COMMISSION

Susan E. Wefald  
Kevin Cramer  
Tony Clark

President  
Commissioner  
Commissioner

In the Matter of the Application by Northern )  
States Power Company, a Minnesota )  
Corporation, for Authority to Increase Rates )  
for Electric Service in North Dakota )  
)

Case No. PU-07-776

**INITIAL BRIEF OF XCEL ENERGY**

This Initial Brief is submitted to the North Dakota Public Service Commission (the "Commission") in support of the December 7, 2007, Application by Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), for authority to increase our base rates for electric service in North Dakota. This Initial Brief also contains our proposal for improving the resource planning process to more fully consider the energy policy interests of North Dakota. We are confident that through a proactive and collaborative effort, the needs and concerns of North Dakota can be fairly addressed in the process, along with the needs and objectives of all stakeholders.

## I. INTRODUCTION.

The Company requests an overall \$17,950,000, or 12.15% percent, increase in our base rates for electric service in North Dakota,<sup>1</sup> allocated in varying proportions among the different customer classes. This base rate increase would be offset by a decrease in the fuel adjustment revenue requirement. For 2008, the offset would have been a \$1,839,000 decrease in fuel adjustment rates, for a net revenue increase of \$16,011,000.<sup>2</sup> This increase in revenues is needed to maintain high quality service to customers and to support funding for future investments.

The last time the Company filed a full electric rate case was 15 years ago, in 1992. Since that time, there have been four decreases and only two minor increases (the latest in 1994),<sup>3</sup> resulting in base rates that have remained essentially unchanged since 1994.<sup>4</sup> In 2007, the Company's average residential electric rates in North Dakota were the lowest of the 16 regional investor-owned utilities serving the Midwestern states of North Dakota, South Dakota, Minnesota, Wisconsin, Iowa, Montana, and Wyoming.<sup>5</sup>

The Company's service reliability in North Dakota is among the best of any of the states it serves.<sup>5</sup> Customer satisfaction among the Company's 86,000 customers

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<sup>1</sup> Ex. 21, Heuer Rebuttal, (AEH-2) Schedule 7, page 1 of 6.

<sup>2</sup> This calculation is based on 2008 test year costs and revenues and reflects the Company's proposal to share 85% of asset-based wholesale margin credits (\$1,800,000) and 15% of non-asset based margin credits (\$39,000) through the fuel clause.

<sup>3</sup> Ex. 4, Larson Direct at 8.

<sup>4</sup> *Id.* at 8-9.

<sup>5</sup> Ex. 5, Larson Rebuttal at 20; Evidentiary Hearing, Vol. I at 20.

in North Dakota is also very high, with customer surveys indicating that approximately 96% of customers have a positive view of the Company's service.<sup>6</sup>

Recent financial results, however, have not corresponded to the value we provide to customers. In 2006 and 2007, the Company's normalized return on equity ("ROE") in North Dakota was 8.85% and 2.96% respectively,<sup>7</sup> which is not sufficient to maintain the financial viability of our North Dakota electric operations or fund future investments. Further, adoption of the recommendations by the witnesses for the Commission's Advocacy Staff would continue the pattern of substandard earnings, disallowing \$13,300,000 of the requested increase (allowing an increase of only \$4,900,000, and leading to an ROE of 4.33%.<sup>8</sup>

These proposed disallowances would not only severely undercut the Company's ability to continue providing high quality service to our North Dakota customers, but would also hinder our ability to address the issues raised by the Commission in this case, such as making future generation investments in the state of North Dakota.

We appreciate the opportunity that this rate case presents for dialog with the Commission regarding past and future resource planning and selection and, as discussed below, we are committed to developing a resource planning process that

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<sup>6</sup> Ex. 5, Larson Rebuttal at 20.

<sup>7</sup> *Id.* at 23.

<sup>8</sup> Ex. 21A, Heuer Rebuttal at 25-26, as adjusted to reflect Mr. King's agreement to recommend cost recovery for the Refuse Derived Fuel generating facilities. *See* Evidentiary Hearing, Vol. III at 665 (King).

addresses the interests of each State in which we operate. But it is essential to distinguish such forward-looking steps from the recommendations to look backward and withhold essential revenues needed to provide service to our North Dakota customers.

While significant financial and future planning issues remain unresolved, a number of issues have been resolved in this proceeding, including:

- The cost of capital, including ROE
- The test year sales forecast
- The prudence of the Company's compensation plan
- MISO costs and the recovery of MISO Schedules 10, 16, and 17 costs through the fuel cost adjustment mechanism
- A mechanism to credit customers for recognition of wholesale margins through the fuel cost adjustment mechanism
- Rate design
- Proposed miscellaneous tariff changes

The remainder of this Initial Brief will present the Company's position regarding the unresolved issues.

## **II. THE COMPANY'S DECISIONS HAVE BEEN PRUDENT AND THE COMPANY SHOULD BE ALLOWED TO RECOVER COSTS ALLOCATED TO NORTH DAKOTA.**

### **A. The Company's Strategies And Decisions Have Led To Low Costs And Fully Met The Prudence Standards.**

Xcel Energy operates in multiple jurisdictions and our integrated portfolio provides low-cost energy and capacity. The Company has acted prudently in developing our resource mix. Further, the cost of complying with obligations imposed on the Company enables ongoing operation of generation that benefits all

customers, and the Company is entitled to recover the proportionate costs from North Dakota customers.

The established ratemaking standard in North Dakota is that all prudently incurred costs are recoverable.<sup>9</sup> The Company meets that standard with respect to investments and expenses included in this rate case. Prudence is based on the Company's selection among available alternatives, not on hindsight, perfection, or whether a decision might have been improved in some way.<sup>10</sup> The Company's decisions meet the standard of prudence because: the Company made reasonable decisions among available alternatives. The decisions have resulted in low costs and high quality service for our North Dakota customers.

The Company's decisions and operation of our integrated system have led to low costs and reliable service in North Dakota. The Company has made reasonable

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<sup>9</sup> See NDCC § 49-06-02, which reads in part: "The value of the property of a public utility, as determined by the commission for ratemaking purposes, is the money honestly and prudently invested therein by the utility . . ." See also *Re Montana-Dakota Utilities Company*, 81 P.U.R. 4<sup>th</sup> 90, (N.D.P.S.C. 1987); *Re Northern States Power Co.*, 139 P.U.R. 4<sup>th</sup> 348 (N.D.P.S.C. 1992); *Re Northern States Power Co.*, 2007 WL 2028346 (N.D.P.S.C. 2007); and *Re Northern States Power Co.*, 127 P.U.R. 4<sup>th</sup> 356, (N.D.P.S.C. 1991).

<sup>10</sup> See *Re Texas Utilities Electric Co.*, 133 P.U.R.4th 604 (Tex.P.U.C. 1991), which defines the prudence standard as "[t]he exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen. . . . This prudence standard does not require perfection. If there is a range of prudent options available to the utility, any choice within the range meets the prudent investment test; the Commission may not substitute its judgment for the utility's judgment by subjectively assessing which of the prudent options is "best." . . . The prudence standard also precludes the use of hindsight. In other words, the Commission must judge the reasonableness of a decision or conduct solely in light of the circumstances, information, and options existing at the time the decision was made or the conduct occurred." See also *Re Missouri Gas Energy*, 2007 WL 2300885 (Mo.P.S.C. 2007); *Re Ladede Gas Co.*, 2007 WL 3225389 (Mo.P.S.C. 2007); and *Re Consolidated Edison Co. of New York, Inc.* 45 P.U.R.4th 325 (N.Y.P.S.C. 1982).

decisions based on available alternatives. For example, our strategy of anticipating future environmental requirements has proven to be cost effective, as will be discussed further in Section III, C, below. Our decisions related to the King and High Bridge Plants are providing significant and important environmental benefits, justifying the inclusion of these projects within the Metropolitan Emission Reduction Program (“MERP”) approval and cost recovery mechanisms of Minn. Stat.

§ 216B.1692. Just as important, those projects provide cost-effective operating improvements and increased energy and capacity to the benefit of all our customers, as will also be further discussed in Section III, B, below. The Company has also incurred costs and made investments that were required as a condition of continued operation of our nuclear generating facilities. These nuclear generating facilities operate at low costs, and the Company’s decision to incur the comparatively modest costs required by the State of Minnesota (such as payments made to the Renewable Development Fund) were clearly more cost effective than closing the nuclear facilities.

**B. Differences Between States’ Policies Do Not Make A Utility’s Compliance Imprudent Or Justify Disallowance Of Costs.**

The primary reason for several of the proposed disallowances is disagreement with certain Minnesota regulatory policies.<sup>11</sup> But that disagreement does not provide a basis to disallow recovery from North Dakota customers of a proportionate share of the Company’s costs of compliance with those policies, because the Company cannot

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<sup>11</sup> Ex. 23, King Direct at 2.

selectively comply with the lawful requirements of the States in which our facilities are located. Further, North Dakota customers obtain substantial benefits from the Company's integrated system.

Disallowing a utility's cost of complying with another State's lawful requirements based on a policy disagreement would place the Company (and other utilities) in an untenable position. In such a situation, a wide range of costs that are not within the Company's control would be subject to disallowance. For example, property taxes, which are collected for the benefit of local residents, could become subject to disallowance if a Commission disagreed with the level or basis for assessing such taxes. A utility cannot operate its facilities without paying applicable taxes, and it would be unable to prevent a revenue deficiency because costs imposed by governmental bodies are outside its control.

The need to recover the costs and investments of complying with lawful requirements enacted by the legislature and state agencies in Minnesota are similarly entitled to rate recovery.

### **III. THE COMPANY'S INVESTMENTS IN GENERATION FACILITIES AND RELATED ENVIRONMENTAL COSTS ARE REASONABLE AND PRUDENT.**

The Company fully demonstrated the prudence and reasonableness of our investments in generation facilities and in our strategy for managing environmental costs. Those investments in our integrated system provide substantial benefits to

North Dakota customers. As a result, those investments and costs should be allowed in North Dakota rates.

**A. The Company Could Not Operate An Integrated System If Some States Disallow Costs Based On Policy Disagreements With Other States.**

Concerns have been raised relating to costs associated with several generation facilities located in Minnesota. We do not believe that any of those concerns reflect any imprudence by the Company. Further, those concerns need to be balanced against the facts that: (i) the Company's 86,000 customers in North Dakota have received high quality service at low cost; and (ii) being part of the Company's integrated system lowers cost and improves reliability and service quality for North Dakota customers. The Company's integrated system: (i) reduces the total quantity of generation resources needed to serve its customers; (ii) allows greater diversity in generation resources; and (iii) lowers the costs of providing service.<sup>12</sup> Each of these features benefit customers in North Dakota.<sup>13</sup> Unless all states allow the Company to recover the proportionate cost of compliance with applicable State laws, the Company's reasonable expectation of cost recovery for operation of its integrated system will be undercut.<sup>14</sup>

The Company's operation of its integrated system and its ability to make future investments rests on its ability to recover all of the costs on a consistent basis from all

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<sup>12</sup> Ex. 5, Larson Rebuttal at 8-11.

<sup>13</sup> *Id.* at 11-12.

<sup>14</sup> *Id.* at 12-14.

States that share in the benefits of that system. The Commission has recognized that customers should share in the costs of achieving savings,<sup>15</sup> and that customers must also share in costs if they are to share in benefits.<sup>16</sup> These principles are fully applicable to both the benefits and savings to North Dakota customers that have been made possible by the Company's integrated system, and to the cost of achieving those savings, which should also be shared by North Dakota customers.

The belief that significant parts of the Company's costs could be disallowed (on the basis of disagreement with Minnesota requirements) without adverse impact on the Company's integrated system is simply not correct. To the contrary, the disallowance of the system costs would provide incentives: (i) for other States to claim a larger share of the cost benefits of the Company's low-cost facilities for customers

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<sup>15</sup> In *Re Northern States Power Company*, 150 P.U.R.4th 524, 527 (N.D.P.S.C., March 24, 1994), the Commission said in part:

Having considered this matter, we believe NSP's purchase of the Viking transmission pipeline will result in reduced gas supply and transportation costs which will more than offset the requested recovery. These savings will flow directly and entirely to NSP's customers in the form of lower retail rates. *We find it reasonable for NSP's customers to share in the cost of achieving these savings.* (Emphasis added.)

<sup>16</sup> See *Re Northern States Power Company*, Docket No. PU-400-00-46, 2000 WL 1505922 at \*1 (N.D.P.S.C., June 20, 2000), stating:

Because NSP has already received approval from the Minnesota and South Dakota commissions, the company intends to begin hedging against price spikes. *Therefore, the commission must decide whether it wants North Dakota ratepayers to share in the costs and benefits of hedging.* If not, the company will reap any gains or losses related to North Dakota's share of hedging results. (Emphasis added.)

See also *Re Northern States Power Company*, 139 P.U.R.4th 348, 354 (N.D.P.S.C., December 15, 1992), where the Commission stated:

The issue is not which allocation method allocates the lowest cost to North Dakota, *the issue is which methods most fairly reflects the reality of the NSP system.* (Emphasis added.)

who paid a proportionate share *of all* related costs;<sup>17</sup> and (ii) for other States to reject additional portions of the disallowed costs. Either result would leave the Company with un-recovered costs that were outside of our control. As a result, the Company would be seriously impeded in planning and operating an integrated system and in making future investments.<sup>18</sup>

**B. The King And High Bridge Projects Were Prudent And Benefit All Customers.**

The Company fully acknowledges that the King and High Bridge plants are providing significant environmental benefits, justifying their inclusion in MERP. However, those environmental benefits result from cost-effective projects that also provide the Company with needed improved reliability, increased capacity and energy, and operational flexibility.

Mr. King proposed disallowing the entire cost of the King Plant rehabilitation and fifty percent of the cost of the High Bridge plant rehabilitation (combined these adjustments total approximately \$4,465,000).<sup>19</sup> Both recommendations were premised on a mistaken belief that: (i) the Company would not have undertaken either project without Minn. Stat. § 216B.1692; and (ii) both projects were premature. Neither of these beliefs is correct.

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<sup>17</sup> *Id.* at 13-15.

<sup>18</sup> *Id.* at 14-15.

<sup>19</sup> Ex. 21A, Heuer Rebuttal at 23-24.

**1. The Rehabilitation Of The King Plant In 2005 Was Prudent And Benefits All Customers.**

Ms. Elizabeth Engelking provided the following information, which demonstrates that the rehabilitation of the King Plant in 2005 was prudent:

- By 2001, the plant's forced outage rate had risen to levels that caused concern, and the plant was experiencing problems typical of a heavily used facility of its vintage.
- In 2001, the Company's Energy Supply division conducted condition assessments of both the plant's boiler and steam turbine. Components of the boiler were failing on a regular basis, reducing the availability, reliability and capacity factor. The frequency of the failures was rising.
- In 2001, Babcock and Wilcox ("B&W"), our consulting engineers, conducted an assessment of the boiler and found that the boiler floor was in poor condition, physically distorted and metallurgically weak. B&W also reported that the floor and the cyclone burners of the King Boilers were the longest surviving original components of 1960's vintage cyclone-fired boilers. The floors and cyclones of all similar boilers built by B&W had been replaced at least once.
- The plant would have ceased operations in 2005,<sup>20</sup> when the rehabilitation began, which is why the Company, in 2003, proposed that the King Plant upgrades be the first MERP project to be implemented.<sup>21</sup>

In addition, Ms. Engelking demonstrated the added advantages gained as a result of rehabilitating the King Plant:

- The rehabilitation reclaimed 60 MW of capacity at very little incremental cost.<sup>22</sup>
- The capacity factor of the plant increased from 74 percent to 82 percent.<sup>23</sup>

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<sup>20</sup> Ex. 10, Engelking Rebuttal at 7.

<sup>21</sup> *Id* at 9-10.

<sup>22</sup> *Id* at 8-10.

- The life of the plant was extended 25 years or more.
- Rehabilitating the plant was accomplished at approximately one-third the cost of constructing a new coal-fired facility, and the cost of additional transmission to serve a new plant would have further increased that cost differential.<sup>24</sup>

In contrast, Mr. King provided no evidence that the plant would not have shut down or that the plant should not have been rehabilitated in 2005.<sup>25</sup> Rather, Mr. King's sole justification for disallowing all of the cost of the King Plant rehabilitation was an out-of-context comment by Ms. Engelking during an informal presentation that Mr. King interpreted and accepted as conclusive proof that the King Plant "would probably not have been rehabilitated as soon as it was without the MERP program."<sup>26</sup>

Ms. Engelking's casual statement, as interpreted by Mr. King, is insufficient to support any disallowance, much less the total disallowance recommended by Mr. King, especially in the context of the unrefuted evidence provided by the Company. Further, Mr. King did not seek clarification of Ms. Engelking's statement. For example, he never inquired by how much the rehabilitation might have been accelerated. Had he done so, Ms. Engelking could have corrected the

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<sup>23</sup> Ex. 3, Larson Direct at 17.

<sup>24</sup> *Id.*

<sup>25</sup> See Evidentiary Hearing, Vol. III at 645-646, where Mr. King stated the following:

Q. What year would the plant have been rehabilitated?

A. She did not say.

Q. What do you say?

A. I don't say.

<sup>26</sup> *Id.* at 646 (King).

misunderstanding in advance of her Rebuttal Testimony, where she clearly demonstrated that the King plant would have shut down in 2005 without rehabilitation.<sup>27</sup> Further, Mr. King's adjustment does not take into account the improved capacity and efficiency of the plant.

Accordingly, the Company's unrefuted evidence fully demonstrates that the King Plant rehabilitation was prudent and benefits all of our customers.

## **2. The High Bridge Conversion Was Also Prudent And Benefits All Customers.**

The Company's decision to convert the High Bridge plant to an intermediate gas combined cycle facility was prudent and provides substantial benefits to all customers. The Company reasonably determined that the combined cycle plant better met our particular resource needs to match hourly changes in load and resource conditions (including wind following capability needed in conjunction with new wind generation), and provides significant additional needed capacity, instead of rehabilitating the existing coal plant at the site. Mr. King did not take those resource needs into consideration when making his disallowance recommendation.

The information provided by Ms. Engelking clearly demonstrates that:

- The High Bridge plant was nearing the end of its useful life.
- The conversion to natural gas increased capacity by 276.4 MW (almost double), benefiting our entire system.

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<sup>27</sup> Further, even if the Company had delayed a year (and the record does not support even a one-year delay), there would have been no impact on the test year revenue requirement, other than an increase in cost as a result of inflation.

- The operational flexibility of the new gas-fired units provides improved system reliability, as our system responds to hourly changes in resource and load conditions. This operational flexibility will become increasingly important as the Company adds future wind generation to our system.
- The conversion allowed the Company to defer investment in new, green-field capacity and energy for several years, which would have been necessary if coal rehabilitation of the site had been selected. Adding capacity at a different location would have required the Company to incur the added cost of acquiring land, developing the infrastructure and building transmission -- all of which were already present at the High Bridge site.
- The Company was able to acquire low-cost turbines on the secondary market, and the current estimated cost of a new combined-cycle generating plant is 33 percent higher than the cost of High Bridge.
- Using a different site would have delayed bringing the additional capacity on line.
- Additional capacity within the Twin Cities Metropolitan load center ensures transmission stability and minimized overall transmission congestion, which also helps mitigate MISO Day 2 congestion costs.<sup>28</sup>

Ms. Engelking also testified to the significant problems associated with attempting to rehabilitate the coal facility at that site, including:

- The impossibility of expanding generating capacity using coal at High Bridge, due to the limited space for plant expansion and coal inventory.
- While the costs of the environmental controls for the coal rehabilitation would have cost approximately one-half the cost of the combined cycle plant: (i) the coal plant would have provided only *half of the capacity* of the combined cycle plant; and (ii) the cost of the rehabilitation of the High Bridge coal plant would have further increased the cost of that alternative.

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<sup>28</sup> Ex. 10, Engelking Rebuttal at 10-15.

- The difficulties of implementing the coal rehabilitation, including significant delays in implementation, limiting the plant's continued role as an effective contributor to overall system reliability.<sup>29</sup>

The Company correctly concluded that conversion to a natural gas combined cycle facility was the correct choice.<sup>30</sup>

Mr. Richard Rosvold provided further evidence of the prudence of the King and High Bridge projects, testifying that the conversion from coal to natural gas at the High Bridge and Riverside plants and the NOx controls installed at the King Plant are saving the customers between \$52 million and \$96 million per year in NOx allowances. As a point of reference, the King Plant NOx control device cost approximately \$60 million, roughly equivalent to a single year of the otherwise required NOx allowance purchases.<sup>31</sup>

Mr. King did not dispute any of this evidence. He agreed that the 33 percent cost savings identified by Ms. Engelking were "probably true."<sup>32</sup> He testified that he had no opinion whether the Company needed the improved system reliability from the load and resource matching flexibility provided by the new gas-fired units.<sup>33</sup> For Mr. King, the issue simply is "whether the High Bridge plant expansion of capacity as a gas-fired combined cycle turbine is required in 2008 to meet the company's

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<sup>29</sup> *Id.*

<sup>30</sup> The Minnesota Pollution Control Agency ("MPCA") also concluded that the costs of the anti-pollution control equipment and rehabilitation made the coal alternative not cost-effective.

<sup>31</sup> Ex. 11, Rosvold Rebuttal at 15.

<sup>32</sup> Evidentiary Hearing, Vol. III at 657 (King).

<sup>33</sup> *Id.* at 658 (King).

needs.”<sup>34</sup> While Mr. King’s perspective fails to consider all of the advantages of the King and High Bridge projects, the Company’s 2000 Integrated Resource Plan (“IRP”) filing and 2002 IRP filing both demonstrate the need for the additional capacity provided by the King and High Bridge projects, as discussed below.

**3. Both The King And High Bridge Projects Provide Needed Additional Capacity For Our Customers.**

The King and High Bridge projects provide approximately 334 MW of additional capacity and energy, and the King Plant has improved its capacity factor by 15 percent, further increasing the amount of available capacity and energy from the facility. This added capacity and energy was needed at the time that it was provided.

It is appropriate for the North Dakota customers to pay their proportionate share of the cost of providing additional capacity and energy needed by the Company’s customers. Further, the cost of supplying North Dakota customers with replacement capacity and energy would be higher than their proportionate share of the King and High Bridge project costs.

Mr. King agreed that, if the Company needed that additional capacity, then North Dakota customers should pay their proportionate share.<sup>35</sup> Mr. King would

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<sup>34</sup> *Id.*

<sup>35</sup> Mr. King testified:

Q. So if, in fact, Xcel Energy needed the capacity it has added to its system, it should be allowed to recover those costs?

A. Yes.

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look solely to the Company's 2000 IRP for evidence that the added capacity was needed.<sup>36</sup> The Company's 2000 IRP demonstrates the need for the added capacity. However, both the Company's 2000 and 2002 IRP filings are relevant to the issue of whether the additional capacity is needed, and both IRP filings demonstrate that the Company needed the additional capacity.

**a. The Company's 2000 IRP filing demonstrates the need for additional capacity provided by King and High Bridge.**

The Company's 2000 IRP filing identified the need to add up to 555 MW by 2005, and the need to add up to 715 MW by 2007 (after conservation and load management goals have been subtracted).<sup>37</sup> The 2000 IRP also stated that feasibility studies would be completed in 2001 related to the possible conversion of the High Bridge and Riverside facilities from coal to natural gas.<sup>38</sup> The Company's 2000 IRP included rehabilitation of the King Plant because that plant was part of the base

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... if that capacity was needed independent of the MERP project, the costs should be allowed. On the other hand, if the capacity was not based on load requirements in 2008, but merely a hedge against future capacity requirement, then I don't think it should be allowed in 2008 because the company has temporarily overbuilt its plant.

*Id.* at 652-653. (King).

<sup>36</sup> *Id.* at 650 (King).

<sup>37</sup> See 2000 IRP, Docket No. E002/RP-00-787, filed July 10, 2000, website:

<https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=760790> ("2000 IRP"), at 5, which states:

By 2005, NSP expects cumulative resource needs ranging up to 555 and halfway through the planning period, 2007, needs in the range of up to 715 MW.

<sup>38</sup> *Id.* at 7, stating:

NSP has agreed to continue investigations of the feasibility of converting some of its coal fired plants to natural gas combustion. Within the next year feasibility studies will be completed at High Bridge and Riverside.

analysis.<sup>39</sup> Thus, the combined 334 MW of additional capacity provided by rehabilitating the King Plant and the conversion of the High Bridge Plant is fully consistent with the additional resource needs identified in the 2000 IRP filing.

**b. The Company's 2002 IRP filing also demonstrates the need for the additional capacity provided by King and High Bridge.**

The 2002 IRP filing specifically identified the intention to rehabilitate King, and convert the High Bridge and Riverside Plants to natural gas facilities, and demonstrated the need for the resulting combined additional capacity from all three projects.<sup>40</sup> Figure 3-1 of the 2002 IRP filing, which is reproduced below, presents the results of Xcel Energy's forecast of production capacity requirements compared to

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<sup>39</sup> *Id.* at 6, stating:

For the most part this Resource Plan assumes the existing fossil fleet will continue to operate as it does now through the fifteen-year planning period.

Because the King Plant only had a remaining useful life of five years, its rehabilitation was assumed.

<sup>40</sup> See 2002 IRP, Docket No.: E002/RP-02-2065, filed December 2, 2002 website: <https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=265611> ("2002 IRP"), at 52, which states:

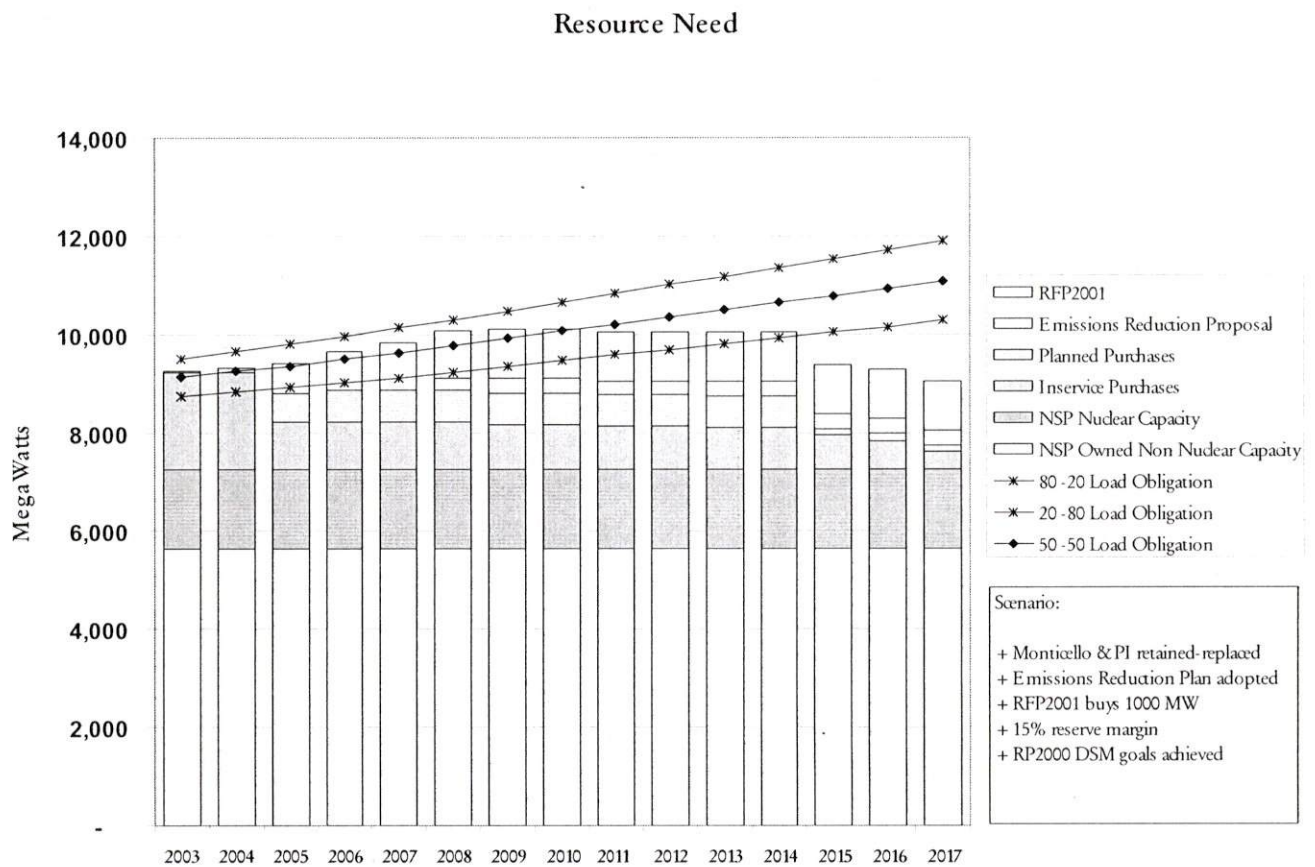
The cycle efficiency improvements will restore approximately 60MW of King's "net dependable" capacity with no increased fuel input.

... This conversion [High Bridge] will ... [provide] a total of approximately 515 MW of creditable capacity, a net increase ... of approximately 244 MW. Because of the change from coal to natural gas, this plant's net dependable capacity will also increase to about 515 MW.

This portion of our proposal [for Riverside] will ... provide ... a net increase in ... capacity of about 56 MW.

The combined net dependable addition in capacity for the three plants is in excess of 400 MW. See Ex. 4, Larson Direct at 15.

existing generation resources and pending generation acquisitions (including the King, High Bridge, and Riverside projects).<sup>41</sup>



This bar graph stacked all of Xcel Energy's then available and proposed resources and compared those with the projected demand under the three forecasts considered by the Company. The bar graph for 2008 demonstrated that when all of the then available and additionally planned capacity were stacked, including the additional capacity provided by King, High Bridge, and Riverside (included in the segment

<sup>41</sup> 2002 IRP, Resource Needs at 27.

“Emissions Reduction Proposal” of the IRP filing), total resources are barely adequate to meet demand in 2008 under either a 20 percent or 50 percent confidence level (resources would be adequate to meet the forecasted demand with a probability of 20 percent or 50 percent). In fact, in order to meet an 80 percent confidence level (resources would be adequate to meet the forecasted demand with a probability of 80 percent), additional new resources were forecasted as being required in 2008.

**4. Minn. Stat § 216B.1692 Did Not Require The Company To Make Environmental Investments.**

Mr. King incorrectly assumed that Minn. Stat. § 216B.1692 *required* the Company to develop a plan for projects that would qualify under that statute.<sup>42</sup> To the contrary, Minn. Stat. § 216B.1692, which was enacted in 2001, established a process for developing, approving and implementing appropriate projects,<sup>43</sup> but it did not require the Company to undertake any project.

Subdivision 2 of the statute provides that a “public utility that **intends** to submit a proposal for an emissions-reduction rider under this section must submit to the commission, the department, the pollution control agency, and interested parties its plans for emissions-reduction projects at its generating facilities.” (Emphasis added.) Subdivision 3 provides in part: “A public utility **may** petition the commission for approval of an emissions-reduction rider to recover the costs of a

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<sup>42</sup> See Evidentiary Hearing, Vol. III at 640-641 (King).

Q. It is your impression that the company was obligated to establish a plan?

A. I believe it was, yes.

<sup>43</sup> Ex. 10, Engelking Rebuttal at 4.

qualifying emissions-reduction project ....” (Emphasis added.) Both provisions indicate the voluntary nature of the MERP statute.

Ms. Engelking confirmed that the Company viewed the statute as voluntary, providing an *improved mechanism* for implementing three projects that were already needed and that benefited all of the Company’s customers:

In fact, the MERP statute prohibits consideration of projects that are mandated or a result of corrective action due to being out of compliance with current standards. Xcel Energy proceeded with development of the three above-described projects [King, High Bridge and Riverside] on a voluntary basis because we believed they would provide significant benefits to our customers throughout our service territories.<sup>44</sup>

The evidence demonstrates that the Company correctly determined that these projects were necessary and beneficial to all of our customers.

## 5. Conclusion.

The King and High Bridge projects reflect the fact that the two facilities had reached the end of their useful lives. The King Plant’s useful life was extended by at least 25 years, at a fraction of the cost of building a replacement plant, while restoring 60 MW of capacity and improving the capacity factor by 15%. The High Bridge project made the most cost-effective use of a valuable location, increasing capacity of the facility by nearly 50 percent. Use of these existing site locations allowed the continued use of existing infrastructure, further decreasing the cost of the projects compared to the alternatives.

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<sup>44</sup> Ex. 10, Engelking Rebuttal at 5.

Mr. King's only question was whether the Company needed the additional capacity in 2008 or was that capacity and energy an unnecessary byproduct of reducing emissions. The Company's 2000 and 2002 IRP filings demonstrate the need for that additional capacity and energy.

**C. The Company's Expenditures For Emission Control Purposes Were Prudent.**

Mr. Rosvold explained that the Company's strategy is to manage emission regulation costs by anticipating future requirements. The Company has found that, by anticipating environmental requirements, rather than simply reacting, the Company improves our ability to budget and plan.<sup>45</sup> Using that strategy, the Company has been successful in reducing the cost of compliance.

Mr. Rosvold provided several examples where this approach has proved beneficial, including the switch from Illinois bituminous coal to low sulfur western coal, and the implementation of NOx controls prior to Phase II of the Acid Rain Program.<sup>46</sup> Similarly, the Company's control efforts undertaken as part of the MERP projects resulted in cost-effective compliance with Federal emission requirements:

- The program met Best Available Control Technology ("BACT") for SO<sub>2</sub>, NOx and particulate matter ("PM"), which significantly reduces the risk of additional environmental improvements that would otherwise be required because of future plant activities.
- The MERP projects have positioned us for compliance with Federal rules that were implemented after the MERP projects were approved, including:

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<sup>45</sup> Ex. 11, Rosvold Rebuttal at 16.

<sup>46</sup> *Id.* at 16-17.

- The Clean Air Interstate Rule (“CAIR”);
  - Clean Air Mercury Rule (“CAMR”); and
  - Best Available Retrofit Technology (“BART”) Determinations under the Regional Haze Rule.
- The resulting savings in NO<sub>x</sub> allowances equates to \$52 million to \$96 million per year. In comparison, the King Plant NO<sub>x</sub> control device cost of approximately \$60 million, roughly equivalent to a single year of allowance purchases.<sup>47</sup>

There is no evidence that a “wait to comply” approach would produce savings compared to the Company’s strategy for managing emission compliance costs.

Mr. King proposed a disallowance of \$438,427, which he believed was the amount included in the 2008 test year associated with the Company’s compliance with the Minnesota mercury control requirements.<sup>48</sup> However, the revenue requirement associated with complying with Minnesota mercury control requirements was approximately \$12,000, not \$438,427. Nor did the Company incur additional emission control costs as a result of including the King Plant in MERP.

The \$438,427 in costs that Mr. King assumed was for mercury control was actually the North Dakota portion of the environmental costs that are recoverable in Minnesota under a special rate rider for emission control costs, including mercury control costs.<sup>49</sup> Included within the \$438,427 is approximately \$200,000 for oxidizing nitrogen equipment at the Sherco Plant (units 1 and 2), approximately \$1,000 in engineering work for mercury sorbent injection systems for Sherco unit 3 and the

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<sup>47</sup> *Id.* at 12.

<sup>48</sup> Ex. 23, King Direct at 7.

<sup>49</sup> Pursuant to Minn. Stat. § 216B.685.

King Plant, and an additional \$225,000 in chemical sorbents or reagents to be used at the King Plant for removing sulfur dioxide and reducing oxidizing nitrogen. These were all current 2008 costs, not costs for rehabilitation of King or a future program.<sup>50</sup>

Mr. King recognized that the Company was prudent in complying with such requirements, but he recommended that Minnesota customers should pay those costs.<sup>51</sup> Mr. King's position is premised on the belief that North Dakota customers would be best served if Xcel Energy only complied with *current Federal* emissions requirements. To the contrary, as Mr. Rosvold explained, Xcel Energy's strategy is to anticipate changing environmental requirements and implement effective technologies that reduce the risk of future emissions regulation in a prudent and planned manner.

Mr. King also incorrectly assumed that Minnesota has adopted more restrictive standards than the EPA.<sup>52</sup> To the contrary, Minnesota has largely adopted *less stringent* standards than the federal standards.<sup>53</sup> The one possible exception is with respect to mercury. However, as Mr. Rosvold explained, the federal standard for mercury is expected to become stricter than the Minnesota standard.<sup>54</sup>

Further, regardless of whether the Company is required to comply with the vacated Federal mercury standard, the Minnesota mercury standard, or the expected Federal mercury standard, we would comply by using the same approach, a sorbent

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<sup>50</sup> Evidentiary Hearing, Vol. I at 291-292 (Rosvold).

<sup>51</sup> Evidentiary Hearing, Vol. III at 639 (King).

<sup>52</sup> Ex. 23, King Direct at 6.

<sup>53</sup> Ex. 11, Rosvold Rebuttal at 3; Evidentiary Hearing, Vol. I at 293 (Rosvold).

<sup>54</sup> Ex. 11, Rosvold Rebuttal at 8.

injector system. As a result, the capital costs for a mercury removal system would be the same to comply *with any* of the standards.<sup>55</sup> The only difference would be how much sorbent was required, which is a future Operations & Maintenance (“O&M”) cost and is *not included in* the 2008 test year. Thus, the emission control standard used for mercury has had no impact on the test year revenue requirement.

The Company also did not incur unnecessary emission costs associated with rehabilitating the King Plant. The need to rehabilitate the plant is itself not an issue in this proceeding (only the timing of the rehabilitation is an issue). Further, even if the Company had delayed the rehabilitation, the emission control requirements would not have been avoided. As Mr. Rosvold explained:

Q. Did Xcel Energy over-control the King plant?

A. [W]e did not . . . . Once you touch the boiler envelope, and that’s what we would have to do to rehabilitate that boiler by cutting out the bottom and doing whatever else needed to be done, you are now subject to that regulation and you have to demonstrate that you either reduce your emissions or that you go through the full new source process.<sup>56</sup>

Because the Company was able to reduce the emissions from the King Plant, it avoided the new source review process.<sup>57</sup>

The 2008 test year in this proceeding includes neither the equipment nor the sorbent costs related to mercury control. The only additional cost in the test year that

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<sup>55</sup> *Id.* at 9-10.

<sup>56</sup> Evidentiary Hearing, Vol. I at 293-294 (Rosvold).

<sup>57</sup> *Id.* at 286.

resulted from meeting Minnesota requirements is \$12,000 incurred for monitoring mercury emissions. That is a necessary compliance cost, and the information provided through monitoring mercury emissions is useful to the Company in designing and managing future state and Federal compliance efforts for mercury.<sup>58</sup> Mr. King did not have an opinion on the need for the monitoring equipment.<sup>59</sup>

Finally, even if Mr. King's assumptions had been accurate, the Company is required to comply with the laws of the states in which it operates.<sup>60</sup> The Company's expenses and investments to meet Minnesota environmental requirements satisfy the prudence and used and useful standards<sup>61</sup> because the Company's generation facilities in Minnesota could not be operated if those environmental requirements were not

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<sup>58</sup> Ex. 10, Rosvold Rebuttal at 10-11.

<sup>59</sup> Evidentiary Hearing, Vol. III at 667 (King).

<sup>60</sup> In *Northern States Power Co. V. Hagen*, 314 N.W.2d 32, 37-38 (N.D. 1981), the North Dakota Supreme Court said:

In this respect we cannot overlook that NSP *is required by* the FERC order to pay a fixed wholesale rate for electricity to NSP Wisconsin which includes the amortization of the Tyrone loss.

The PSC has no direct jurisdiction over interstate wholesale rates and we believe it would undermine the supremacy clause and the preemption doctrine for the PSC to indirectly assert jurisdiction over the wholesale rates . . . .

We conclude that, for purposes of fixing intrastate rates, the Public Service Commission must treat NSP's filed interstate wholesale rates as a reasonable operating expense. (Emphasis added.)

<sup>61</sup> Under general principles of utility law, the "used and useful" standard simply requires (1) that the property be "in service," and (2) that it "be 'reasonably necessary' to the efficient and reliable provision of utility service." *City of Evansville v Southern Indiana Gas and Electric Co.*, 339 N.E.2d 562, 589-91 (1975); *Public Service Commission v Diamond State Telephone Co.*, 468 A.2d 1285, 1290 (Del.1983); and *Senior Citizens Coalition Of Northeastern Minnesota v Minnesota Public Utilities Commission*, 355 N.W.2d 295 (Minn. 1984).

met.<sup>62</sup> Prudence is based on decisions available to the Company, and the Company cannot operate its facilities unless it meets all applicable requirements. As a result, the cost of compliance is a cost of doing business and all customers should contribute toward those costs in return for service.

The costs of compliance with North Dakota requirements are also a cost that should be recovered proportionately from Minnesota customers. For example, Great River Energy, in its 2008 Resource Plan, has identified the efforts it is undertaking and the costs it will incur to comply with the North Dakota Department of Health BART requirements for air quality.<sup>63</sup> North Dakota regulations apply to generation facilities

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<sup>62</sup> Validly mandated pollution control facilities are routinely considered “used and useful,” and thus included in a utility’s rate base, even though such facilities do not produce or distribute electricity, or aid in doing so. See *Green v Pennsylvania Public Utility Commission*, 473 A.2d 209, 214 (Pa.Comm.1984); *Commonwealth Edison Co. v Department of Local Government Affairs*, 408 N.E.2d 263, 266 (1980), *aff’d*; *AFL-CIO, Central Labor Council of Vanderburgh, Posey and Warrick Counties v Southern Indiana Gas and Electric Co.*, 443 N.E.2d 1243, 1247-48 (Ind.App.1983).

<sup>63</sup> As stated in Great River Energy’s 2008 Resource Plan, at page 34, Docket No.: ET2/RP-08-784, filed July 1, 2008, website:

<https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5314579>:

The U.S. Environmental Protection Agency (EPA) published final regional haze regulations in 1999. The goal of these regulations is to improve visibility in Class 1 areas, such as national parks and wilderness areas, to reach “natural conditions” by 2064. The rule requires certain power plants to install Best Available Retrofit Technology (BART) to control SO<sub>2</sub>, NO<sub>x</sub> and Particulate Matter (PM). Since 2005 Great River Energy has been working closely with the North Dakota Department of Health (NDDH) and has provided detailed BART analyses for each affected unit that identifies feasible control options for each pollutant, cost estimates for the respective controls, expected emission rates and associated visibility improvements for each combination of controls. NDDH is expected to issue their final BART determination soon. These emission controls must be installed and operational no later than 5 years after EPA approves the North Dakota BART State Implementation Plan (SIP), which may be as soon as 2013. Coal Creek and Stanton stations have been working diligently on their BART control strategies and do not anticipate any difficulty meeting the regulatory timelines.

located in North Dakota. Because GRE has no customers in North Dakota, all of the costs of complying with these requirements will be recovered from Minnesota and Wisconsin customers.

The cost of complying with emission requirements is a cost of doing business and is recoverable from all customers.

**D. The Grand Meadow Wind Farm And Transmission Costs For Wind Generation Located In Minnesota Are Reasonable.**

Initially, the Company was required to install wind capacity in Minnesota as a condition of being allowed to install dry cask storage at the Prairie Island nuclear facility.<sup>64</sup> Grand Meadow was part of that wind capacity. Accordingly, the cost of Grand Meadow was a necessary cost of keeping Prairie Island operational and continuing to provide low-cost energy. While the Grand Meadow project and other wind generation facilities are located in Minnesota, the projects have been very efficient and provide very low-cost energy. No lower-cost North Dakota project was

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In 2018, NDDH will start the second round of regional haze reductions. Cost effective controls and associated visibility improvements will again be determined for all emission sources in the state with an effective date of 2023 for any applicable control requirements.

NDDH has authority to adopt and enforce rules implementing the policy of NDCC 23-25-01.1, which provides:

It is hereby declared to be the policy of this state and the legislative intent of this chapter to achieve and maintain the best air quality possible, consistent with the best available control technology, to protect human health, welfare, and property, to prevent injury to plant and animal life, to promote the economic and social development of this state, to foster the comfort and convenience of the people, and to facilitate the enjoyment of the natural attractions of this state.

<sup>64</sup> The requirement of an installation in Minnesota has now been repealed, but it was in effect when Grand Meadow was selected.

available. The Company's decision to acquire the Grand Meadow Wind Farm and other wind projects located in Minnesota was clearly prudent.

Mr. King proposed disallowing 25 percent of the cost of the Grand Meadow Wind Farm and 25 percent of transmission costs related to wind generation located in Minnesota based on the assumption that comparable wind farms located in North Dakota would be 25 percent more efficient and, therefore, 25 percent less costly (a combined disallowance of \$159,175).<sup>65</sup> There are several reasons why Mr. King's recommendation should not be accepted.

Mr. King's assumption that a North Dakota site would be more efficient than our Minnesota based wind generation is incorrect. Mr. King assumes, based on an unidentified source ("I am told"), that capacity factors and the resulting cost of energy on a kWh basis in North Dakota are about 25 percent lower than those of Minnesota wind farms.<sup>66</sup> When asked what the North Dakota capacity factor would be, he testified that it would be in the 40 to 50 percent range.<sup>67</sup> However, even if correct, that does not justify disallowing Grand Meadow related costs because Grand Meadow is projected to achieve a 40 percent capacity factor.<sup>68</sup>

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<sup>65</sup> Ex. 23, King Direct at 13.

<sup>66</sup> *Id.*

<sup>67</sup> Evidentiary Hearing, Vol. III at 660 (King).

<sup>68</sup> *Id.*, Vol. I at 117 (Larson).

Mr. King also acknowledged that the Buffalo Ridge in Minnesota offers comparable wind resources to those in North Dakota, but over a smaller area.<sup>69</sup> In addition, while the early Minnesota wind projects had capacity factors of 34.7 percent, that capacity factor was a reflection of early technology, not location. The Velva, North Dakota Wind Farm, for example, had a capacity factor of 31 percent.

As Ms. Engelking explained:

The projected capacity factors in Minnesota are actually quite a bit higher than what has actually been achieved, ... and that has to do with the differences in hub heights, that hub heights are getting much taller, that technology is getting better at capturing the wind. For example we now have turbines that very efficiently capture wind at low wind speeds that we couldn't actually do before.<sup>70</sup>

Mr. King's assumption of superior North Dakota capacity factors is unsupported by the record. Mr. King offered no evidence that wind generation in North Dakota is actually less costly: "And my suggestion is -- and we'll never know -- the North Dakota wind power might have been cheaper yet."<sup>71</sup>

Mr. King's reliance on capacity factors also does not take into consideration a number of other critical factors that make Grand Meadow and other Minnesota based wind generation a lower-cost resource. In particular, both Grand Meadow and the Buffalo Ridge are located closer to the Company's primary load than a potential

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<sup>69</sup> *Id.*

<sup>70</sup> *Id.*, Vol. I at 217-218 (Engelking).

<sup>71</sup> *Id.*, Vol. III at 662 (King).

North Dakota wind project. Mr. King agreed that: “the closer you are to the load center the better.”<sup>72</sup>

In addition, the Grand Meadow project already had Midwest Independent System Operator (“MISO”) approval to access the transmission network, allowing the project to go on line in time to meet the Company’s needs. The interconnection queue with MISO currently contains over 20,000 MW of wind projects in our area, and it is estimated that it will take many years to study and interconnect those proposed projects. Had the Company sought new wind generation in either Minnesota or North Dakota, the project could not have been brought on-line in time.<sup>73</sup>

An additional cost benefit that flowed from the ability to interconnect the Grand Meadow project quickly was the available Federal Production Tax Credit on wind energy, which is set to expire at the end of 2008. This tax credit is worth \$20.00 per MWH for the first ten years, or more than 16 percent of the cost of the Grand Meadow project; and would not have been available for new generation in either Minnesota or North Dakota that comes on line after 2008, unless Congress extends the availability of this tax credit program.<sup>74</sup>

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<sup>72</sup> *Id.* at 661 (King).

<sup>73</sup> Ex. 10, Engelking Rebuttal at 18-19.

<sup>74</sup> *Id.* at 19.

Ms. Engelking explained that the Company selects its wind projects using competitive bidding. If a North Dakota wind project had bid a lower cost, it would have been selected.<sup>75</sup> All of the evidence supports the conclusion that the existing wind energy was the lowest-cost alternative at the time. In 2007, the average cost of wind on our system was \$32.16/MWh, while the average MISO market price was roughly \$55.00/MWh. In addition, the wind energy has avoided emissions of SO<sub>2</sub> and NO<sub>x</sub>, allowing Xcel Energy to avoid purchasing the allowances needed to emit those pollutants.<sup>76</sup> Therefore, without wind in our portfolio, all of our customers -- including North Dakota customers -- would have paid higher rates for their energy.

The cost of transmission to the Buffalo Ridge was, in total, approximately \$300 million, including all of the associated costs for wind collector substations and transmission to the bulk power electric system.<sup>77</sup> The cost of the CapX Fargo-Twin Cities 345 kV line that will assist in bringing North Dakota based wind generation to the Company's primary load is projected to cost between \$390 million and \$560 million (depending on actual length). That cost does not include all of the additional costs for developing wind collector substations, transmission to deliver the wind generation to the bulk electric system, or any upgrades to that system that may be

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<sup>75</sup> *Id.* at 19.

<sup>76</sup> *Id.* at 18.

<sup>77</sup> Evidentiary Hearing, Vol. I at 320-321 and 329 (Grivna).

necessary to reliably deliver the energy to connect to the 345 kV line in the Fargo area.<sup>78</sup>

Mr. Walter Grivna explained that the Company could not install wind generation in North Dakota to serve just North Dakota load. The Company operates an integrated transmission system and that system is incompatible with isolating generation to serve just North Dakota load.<sup>79</sup> Mr. Grivna also explained that the existing transmission network between North Dakota and Minnesota is not adequate to serve significant new wind generation for the Company (other utilities with baseload generation in North Dakota can reduce their reliance on that generation when wind generation is available and, thus, are able to use their existing transmission).<sup>80</sup>

While installation of separate wind generation serving only our North Dakota load is not feasible, Xcel Energy plans to develop wind generation in wind-rich areas throughout our service area, including North Dakota. A primary impediment to date has been the lack of adequate transmission -- a constraint that is being addressed by the CapX Fargo to Monticello project.<sup>81</sup> Xcel Energy recognizes the benefits of

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<sup>78</sup> Ex. 31.

<sup>79</sup> Evidentiary Hearing, Vol. I at 325 (Grivna).

<sup>80</sup> *Id.* at 325-326.

<sup>81</sup> Ex. 10, Engelking Rebuttal at 19.

diversifying wind resources over as large an area as possible and is affirmatively planning and investing in our system to this end.<sup>82</sup>

The record shows that there is no basis in the record to disallow 25 percent or any other portion of the wind generation and associated transmission.

**E. Refuse Derived Fuel Generation Is Prudent And Benefits All Customers.**

The Company's Refuse Derived Fuel generation plants are reasonable and prudent resources used to meet the energy and capacity needs of all customers and should be included in the revenue requirement. Mr. King proposed disallowing \$173,000 for three Refuse Derived Fuel generation plants that have been in service for many years, based on his assumption that they had been added in response to a Minnesota requirement.<sup>83</sup> No other reason for their disallowance was offered. While the Company is allowed to count these plants (along with preexisting hydro) toward its renewable energy requirements, these projects were *not undertaken* in response to a Minnesota renewable energy requirement. On that basis, Mr. King recommended withdrawing the proposed disallowance.<sup>84</sup>

The record shows that:

- The Red Wing plant, a 20 MW plant, was constructed in 1949 as a coal plant and converted to Refuse Derived Fuel in 1984;

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<sup>82</sup> *Id.* at 30.

<sup>83</sup> Ex. 23, King Direct at 12.

<sup>84</sup> Evidentiary Hearing, Vol. III at 665 (King).

- The Wilmarth plant, a 20 MW plant, was constructed between 1941 and 1948 as a coal plant and converted to Refuse Derived Fuel in 1984; and
- The French Island plant, a 25 MW plant, was constructed as a coal plant between 1940 and 1948 and was converted to burn wood waste and Refuse Derived Fuel in 1986.

These facilities have been a reliable part of the Company's integrated system since the 1940s, and were converted to Refuse Derived Fuel long before the Minnesota legislature passed any renewable requirements. They were also approved as a part of North Dakota electric rates in our 1992 and prior rate cases.<sup>85</sup> Accordingly, there is no basis for disallowance.

**F. The Renewable Development Fund Is A Necessary Cost Of Operating The Prairie Island Nuclear Facility.**

The Company's Renewable Development Fund ("RDF") is reasonable and prudent, and its costs should be included in the revenue requirement. The record shows that: (i) the Commission has previously allowed cost recovery for research and development costs; (ii) the RDF research is a cost of providing service that benefits North Dakota customers; and (iii) the Company was required to incur the RDF costs in order to continue operating the Prairie Island nuclear facility.

The Commission has previously allowed cost recovery for research and development expenses.<sup>86</sup> The fact that the RDF was required by Minnesota law does not reduce the benefit to customers outside of Minnesota. Renewable resources will

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<sup>85</sup> Ex. 10, Engelking Rebuttal at 21.

<sup>86</sup> See *Re Otter Tail Power Co.*, Case No. 9996 (April 22, 1980) (approving expenses allocated to the Electric Power Research Institute, for research and development of a fast breeder nuclear reactor).

be a critical component of all utilities' portfolios for the foreseeable future, and it is reasonable to work toward developing more efficient mechanisms to generate energy and capacity from renewable resources.

The Company has not sought recovery of costs that are expected to only benefit Minnesota interests. The test year includes \$170,000 in RDF expenses, representing the North Dakota allocated share of the energy production ("EP") grant payments and a portion of the RDF administrative costs (prorated based on target funding for energy production grants versus research and development ("R&D") grants in the 3rd RDF Funding Cycle Request for Proposal).<sup>87</sup> The test year does not include expenditures related to R&D and Renewable Energy Production Incentives, which are born directly by Minnesota electric retail customers.<sup>88</sup>

Mr. King proposed disallowing \$170,000 in expenses for the Company's RDF because the RDF is a response to Minnesota requirements and should be charged only to Minnesota customers.<sup>89</sup> However, the lack of a Minnesota specific benefit is reflected in the fact that approximately 20 percent of the total R&D funds have benefited North Dakota organizations.<sup>90</sup>

The RDF expenses are also a cost of operating the Prairie Island nuclear facility. In exchange for receiving authority to have on-site interim nuclear fuel

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<sup>87</sup> Ex. 21A, Heuer Rebuttal at 14.

<sup>88</sup> *Id.*

<sup>89</sup> Ex 23, King Direct at 12.

<sup>90</sup> See Ex. 21A, Heuer Rebuttal, Schedule 1, which contains additional detail on grant awards to North Dakota based projects.

storage at the Prairie Island nuclear facility (dry cask storage), the Company is required to fund the RDF. The total annual funding of the RDF in relation to the dry casks located at our Prairie Island nuclear facility is \$16 million.<sup>91</sup> If the Company refused to provide the required RDF funding, the operation of the two nuclear generating facilities would be impossible, and the Company would be required to replace approximately 1,670 MW of capacity, of which the North Dakota share is 82 MW.<sup>92</sup> The replacement costs of 82 MW would greatly exceed the \$170,000 of RDF costs.

For these reasons, the Commission should approve cost recovery of the North Dakota share of the RDF fund.

#### G. Conclusion.

The Company demonstrated the prudence and reasonableness of the challenged costs. While the MERP projects provided needed environmental improvements, the King Plant was rehabilitated because it needed rehabilitation; and High Bridge was converted from a coal plant to an intermediate combined cycle natural gas facility because the Company needed the additional capacity and the resource matching flexibility provided by the facility at that location. The emission control costs at the King plant were required by the rehabilitation of the plant (a necessary action) and MERP did not increase those costs. The Refuse Derived Fuel

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<sup>91</sup> Minnesota legislation passed in 2007 will also require the Company to provide funding of \$350,000 per cask located at our Monticello nuclear facility. We expect to be required to fund \$3.5 million related to Monticello dry casks in 2008.

<sup>92</sup> Ex. 21A, Heurer Rebuttal at 14.

plants were not mandated and are a reasonable component of the Company's generation portfolio.

The Company's emission control efforts have provided significant cost savings. The only "mandated" mercury control cost included in the test year is \$12,000 for mercury emission testing, a reasonable and prudent cost of providing service. Grand Meadow and the other wind projects selected through a competitive bidding process, along with the associated transmission, provide the least-cost available wind generated energy.

The cost of the research and development conducted as a result of the RDF benefits all of the Company's customers and is a recoverable expense. Further, to the extent the RDF or other requirements were incurred by the Company in order to keep the Prairie Island Plant operational, that is a cost of doing business that is recoverable in rates from all customers.

#### **IV. THE COMPANY'S DEPRECIATION EXPENSE IS REASONABLE.**

The Company demonstrated that our depreciation expense is reasonable and that we have appropriately used the average life approach for categories of assets where there are large quantities of comparable plant categories (transmission, distribution and general structure plant assets) and we appropriately use the more individual and specific remaining life approach for unique plant categories (generation facilities) where investments and other specific events can have a significant impact on

the life of specific assets. The Company also uses established accrual accounting practices for determining and recovering the cost of retiring assets.

Mr. King and Mr. Majoros proposed using the remaining life methodology for all assets. They also made recommendations that would: (i) extend the lives of current investments beyond the useful lives of that investment; (ii) use the present value cost of retirements rather than the future cost of retiring assets; and (iii) refund amounts previously recovered under prior Commission authorized retirement cost recovery policies.<sup>93</sup> Each of these proposals would shift cost recovery from current customers to future customers, and create significant intergeneration inequities contrary to long-standing regulatory principles that costs should match the benefits received.

**A. The Company's Uses Of The Whole Life And Remaining Life Methodologies Are Reasonable.**

Xcel Energy uses whole-life and remaining life methodologies for the appropriate types of assets.

For transmission plant, distribution plant and general structure plant accounts, Xcel Energy uses a whole-life calculation where the investment is allocated over the full life of the assets. Mr. Jeffery Robinson explained that the whole life methodology: (i) is recognized as an appropriate methodology for transmission plant, distribution plant and general structure plant accounts; (ii) is more appropriate for non-production facilities; (iii) is less burdensome to administer than the alternative remaining life

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<sup>93</sup> Ex. 23, King Direct at 18-33.

methodology; and (iv) both methodologies recover the same cost over the life of the asset. Because the accrual rate under the whole-life methodology is based on the average life of a large group, the difference between accruals for early retirements of individual assets will be balanced by those assets having longer than average lives.<sup>94</sup>

As Mr. Robinson further explained:

The Company uses the whole-life technique because it is applying that to groups of assets that ... have many components that are of like kind. Overhead conductor, for example, is many spans of a like kind type property.<sup>95</sup>

The result is that differences in actual experience are largely offset and the group as a whole will be fully depreciated by the time of final retirements. This is the standard method used across the industry to model depreciation for transmission, distribution and general plant assets.

The Commission has approved the whole-life technique in every rate case since the beginning of Commission regulation in North Dakota. Any potential improvement in cost recovery matching (under the remaining life methodology) is more than out-weighted by the higher burden involved in using that methodology for routine transmission, distribution and general structure plant accounts.

The Company uses a remaining life methodology for its unique production facilities. This methodology requires an annual, asset-specific recalculation of the

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<sup>94</sup> Ex. 18, Robinson Rebuttal at 3-4.

<sup>95</sup> Evidentiary Hearing, Vol. II at 429-430 (Robinson).

depreciation expense based on updated information concerning the remaining years of life and the net salvage. This asset-specific methodology is reasonable where the number of assets is few and the associated costs are large, as is true for production assets. As Mr. Robinson explained: “Our generating plants are quite unique, one to the other, and we rigorously assess the life of each one of those individual components . . . .”<sup>96</sup>

The remaining-life technique requires more precision in the estimated life and dispersion of retirements than the whole-life technique. Consequently, its added burdens are justified for the few, unique and high-cost production plants. It is not justified for the transmission, distribution and general structure plant accounts.<sup>97</sup>

Mr. King recommended that the Company be ordered to cease using the “whole life” methodology for calculating depreciation expense for transmission, distribution and general structure plant assets and to use instead the “remaining life” methodology. Mr. King’s reason for this suggestion is that the remaining life methodology provides a self-correcting mechanism to eliminate excess or insufficient depreciation accruals.<sup>98</sup> However, the remaining life method is not advantageous for the large numbers of transmission, distribution and general structure plant assets. The

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<sup>96</sup> Evidentiary Hearing, Vol. II at 430 (Robinson).

<sup>97</sup> Ex. 18, Robinson Rebuttal at 5.

<sup>98</sup> Ex. 23, King Direct at 19.

proposed change from whole-life to remaining-life depreciation for these assets appears to reflect Mr. King's preference rather than any demonstrated benefit.

**B. The Company's Specific Useful Lives Are Reasonable.**

The Company demonstrated the reasonableness of the useful lives used in our depreciation studies. The useful lives for generating units are determined based on a detailed and comprehensive evaluation of each unit. The useful lives of transmission, distribution and general structure plant assets are based on actual experience and engineering analysis.

Mr. King proposed \$4,100,000 of adjustments based on proposals to extend the lives of the Sherco Plant, the Prairie Island nuclear facility, and five of the gas peakers beyond the useful remaining lives of the current investment in those plants. Mr. King's recommendations were based on industry averages and were not based on plant-specific analysis.

The remaining life of a plant needs to be determined based on facts related to the particular asset, not the average life of all plants. Mr. King, in discussing the principles of depreciation stated: "At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the plant."<sup>99</sup> Using an average of all plants is not an adequate estimate of the service life of a particular plant. Further, as Mr. Robinson observed, an average service life only has relevance if it is

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<sup>99</sup> *Id.* at 17.

applied to all plants, such that, on average, it is accurate. At a minimum, that would require the application of an average service life to all of the Company's generation units, not just to those which have less than average lives.<sup>100</sup>

Mr. King's recommendations also do not consider the additional investments that would be needed to extend production plant lives. As a result, Mr. King's proposal is inconsistent with the purpose of depreciation, which is to return the *current* investment in an asset during that investment's useful life. In addition, his recommendation fails to match the depreciation expense associated with an investment to the customers who benefit from that investment. He has, instead, shifted the recovery of investment (depreciation) with limited useful lives to future customers who will receive no benefit from the investment, and who will also be required to pay depreciation on the later rehabilitation costs that justify a life extension. Consequently, Mr. King's proposed life extensions for generating units violate the purpose of depreciation and the principles of matching and should not be accepted.

Mr. King also proposes to extend the life for overhead conductors based on incorrect assumptions concerning the impact of vegetation control on the lives of those assets, and his assumption that climate differences in North Dakota justify longer lives.

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<sup>100</sup> Ex. 18, Robinson Rebuttal at 11.

## 1. Sherco Unit Lives Should Not Be Further Extended.

The Company fully supported its useful remaining life determination for the current investments in the Sherco plant. Mr. King proposed increasing the life expectancy of two of the Sherco units (units 1 and 2) from 44 years to 59 years and the third unit from 33 years to 59 years.<sup>101</sup> Mr. King offers no support for this proposal other than the claim that, on average, other steam plants have lived to be 59 years old. Using an industry average to substantially increase the life of a unique facility is inconsistent with the rationale for using the remaining life methodology advocated by Mr. King and used by the Company for generating units.

Mr. Robinson described the Company's use of the remaining life methodology for its generating plants as follows:

Each year, Xcel Energy is required to reexamine the remaining lives of its generating units based on the facts and circumstances surrounding each unit. Some of the components are:

- Fuel and fuel resource changes
- System capacity requirements
- Pollution control equipment and environmental standards
- Major construction projects
- Major replacement and repair projects
- Maintenance programs for plant equipment
- Other related contracts tied to operating life.

When any new production plant goes into service, an initial life is set based on consideration of function (i.e. base load for Sherco, peaking for combustion turbines), fuel and system capacity, along with other factors. In addition, the Company conducts a detailed Integrated Resource

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<sup>101</sup> Ex. 23, King Rebuttal at 22.

Planning study to determine the projected lives of all of its generating units. As part of its annual remaining life update study, the Company also interviews plant management to determine if any conditions in the plant have changed to warrant a change in retirement date for any generating unit.<sup>102</sup>

Consistent with that practice, the Company has a request pending with the Minnesota Public Utilities Commission (“Minnesota PUC”) to extend the lives of several plants:

<u>Unit</u>	<u>Present Retirement Date</u>	<u>Proposed Retirement Date</u>
Sherco 1 & 2	2019	2022
Sherco 3	2020	2022
Blue Lake 1-4	2010	2012
Key City	2009	2012
Granite City	2009	2012 <sup>103</sup>

The Company’s process is consistent with Mr. King’s Direct Testimony that the remaining-life methodology “provides a self-correcting mechanism to eliminate excess or insufficient depreciation accruals.”<sup>104</sup>

Mr. King’s proposed life extension for the Sherco units was not based on any plant-specific analysis. Rather, it was based on the assumption that these *unique* units would have an *average* useful life. Mr. King’s proposal also does not consider the

<sup>102</sup> Ex. 18, Robinson Rebuttal at 5-6.

<sup>103</sup> *Id.* at 13.

<sup>104</sup> Ex. 23, King Direct at 19. It is highly likely that the results of the Company’s proposal will be known before setting final rates in this case, and the Company proposes incorporating any approved changes in its compliance filing calculating final rates.

extensive rehabilitation costs that would be needed to accomplish such a life extension.

Mr. Robinson testified that for the Sherco units to have the 25 and 37 year life extensions proposed by Mr. King, many investments would be needed, including: (i) replacement of turbine stationary and rotating components at least once on all three units; (ii) replacement of the generator, main, and reserve transformers at least once on all three units; (iii) replacement of the cooling towers at least once on all three units; (iv) replacement of boiler sections on unit 3, and possibly twice on units 1 and 2; (v) replacement of control systems at least twice on all three units; (vi) expansion of ash disposal systems (ash storage ponds and ash landfills); (vii) upgrading of fuel handling and processing equipment; (viii) replacement of selective catalytic reduction equipment would be needed to reduce NO<sub>x</sub> emissions; and (ix) replacement of infrastructure (roads, building, communications). All of these rehabilitation projects are included in the Company's capital project plans for the future.<sup>105</sup> However, the current investment in these units does not have a useful life of 59 years, and Sherco cannot have a useful life of 59 years without massive new investment.

Assuming life extensions without considering the investments needed to achieve life extension can have dramatic effects. For example, the King plant required

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<sup>105</sup> *Id.* at 11.

a \$471,700,000 investment in order to extend its life from 37 years to 62 years.<sup>106</sup>

Under the remaining life methodology, the King Plant's remaining life, after the rehabilitation was completed in 2007, was 25 years and the \$471,700,000 of additional investment will be recovered over those 25 years. Application of Mr. King's average life methodology to the King Plant in the year 2000 would have led to the conclusion that the King Plant had a useful life of 59 years instead of the actual 5 years of remaining useful life in the then existing investment.

Mr. King's approach would not have included the \$471,700,000 needed to actually extend the useful life of the King Plant to 59 years in determining the depreciation rate in December 2005 (because it would not yet have been spent). Using Mr. King's methodology, the depreciation rate would have decreased significantly during the 2000 to 2007 period. But, as of the date of the actual life extension in 2007, the depreciation rate would need to collect both the remaining uncollected initial investment (the useful life of which ceased in 2005) and the \$471,700,000 rehabilitation cost. Mr. King's methodology provides a rate reduction today by shifting the cost recovery responsibility of today's customers to tomorrow's customers.

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<sup>106</sup> Ex. 18, Robinson Rebuttal at 10.

## **2. Combustion Turbine Production Plant Lives Should Not Be Extended.**

The Company fully supported its useful remaining life determination for the current investments in the combustion turbines. Those useful lives are based on the remaining lives of the current investment in those plants based on a comprehensive analysis of each unit.

Mr. King recommended a life extension for five combustion turbine plans to 45 years, again based on using the average life of all combustion turbine plants. In one case, his recommendation results in over a 75 percent increase in the life of a unit.<sup>107</sup> For the same reasons the Sherco units should not have their lives extended using an average life, the combustion turbine plants should not be extended based on an average life.

As is required by the remaining-life methodology, the Company annually conducts a rigorous analysis of the facts and circumstances surrounding each of the generating units to determine the retirement date. Before the actual lives of the units can approach the average life proposed by Mr. King, very significant rehabilitation investments would be required. Mr. King's proposal does not consider these rehabilitation costs. Consequently, Mr. King's proposal extends the life of the combustion plants beyond the useful life of the current investment in those plants.

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<sup>107</sup> Ex. 18, Robinson Rebuttal at 11.

Mr. Robinson explained that eight of the combustion plant units would need major overhauls before they could have the useful lives proposed by Mr. King.<sup>108</sup> In addition, those units would need to run for 24 consecutive months in the previous five years to avoid triggering new source review from an environmental perspective.<sup>109</sup> If new source review were required, it would not be economical to restore and run these units with the best available control technology. Life extensions for the other units are expected to be addressed through continued aggressive maintenance but would require upgrades of control systems, replacement of inlet silencers and exhaust diffusers, and replacement auxiliary coolers.<sup>110</sup>

Further, because Mr. King's proposal extends the life of the current investment beyond its useful life, those investment costs would be recovered from future customers who would not have benefited from the investment, causing an improper matching of costs and benefits.<sup>111</sup>

### **3. It Would Be Premature To Extend The Life Of The Prairie Island Nuclear Facility.**

Xcel Energy is seeking authority to relicense the Prairie Island nuclear facility with the Nuclear Regulatory Commission ("NRC"). Based solely on that fact, Mr. King proposes extending the life of Prairie Island by 20 years. While the Company is working toward obtaining the necessary license to accomplish a 20-year life extension,

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<sup>108</sup> *Id.* at 12.

<sup>109</sup> *Id.*

<sup>110</sup> *Id.*

<sup>111</sup> *Id.* at 10-11.

a filing with the NRC is not a guarantee of approval and is not the basis upon which a life extension for depreciation purposes should be made.

The work and expense involved in filing for an extension and actually extending the life of a nuclear plant is massive. In addition, approximately \$180,000,000 in capital improvements will be needed to realize a twenty-year life extension and to meet the NRC license extension requirements.<sup>112</sup> The remaining life methodology determines the remaining life based on existing investments. To extend the life based on future investments without including those investments is “a mismatch between the realizable life and the investment made to realize that life.”<sup>113</sup>

#### **4. The Life Of Overhead Conductors Should Not Be Extended.**

The Company’s useful life for overhead conductors is based on actual experience and engineering studies, is reasonable, and should be accepted. Mr. King proposes a 40-year life (a 5 year extension) for overhead conductors based on the fact that Xcel Energy has increased its vegetation control efforts.<sup>114</sup> Mr. King also assumed that North Dakota has fewer trees than Minnesota, and consequently that overhead conductors would have a longer life in North Dakota than in Minnesota.<sup>115</sup> These assumptions are not borne out by the Company’s actual analysis of the useful life of overhead conductors.

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<sup>112</sup> *Id.* at 14.

<sup>113</sup> *Id.*

<sup>114</sup> Ex. 23, King Direct at 26.

<sup>115</sup> Evidentiary Hearing, Vol. III at 702 (King).

The Company has carefully analyzed the impact of trees and vegetation management on the useful life of its overhead conductors. As Mr. Robison explained, the nexus between vegetation control and useful lives assumed by Mr. King does not exist:

Very few of the retirements of distribution overhead conductors are caused by trees hitting lines that are preventable by a cyclical tree-trimming program. The root-cause analysis for tree-related outages is tracked by the Vegetation Management Department of Xcel Energy. That Department investigates every outage involving trees and power lines. One of the main objectives of these investigations is to determine whether the outage was preventable or not. Simply stated, a preventable event is an event that could have been prevented if Xcel Energy had performed routine maintenance on the tree in question the day before the event occurred. Non-preventable tree-related outages typically occur from live broken limbs outside of the normal maintenance zone or uprooted trees outside the right-of-way where the Company could not reasonably predict their failure. Since 2002, Xcel's root-cause investigation of the actual events in North Dakota suggests that 80% (40 out of 50) were non-preventable events. In other words, very few of the retirements caused by trees hitting distribution lines are preventable by a more aggressive tree trimming program. Although there are many other positive benefits from focusing more efforts on tree trimming, reducing the level of retirements caused by trees damaging distribution conductors is not one of them.<sup>116</sup>

Mr. King's proposal is based on assumed differences in precipitation and his casual observation of the trees from an airplane when landing in the Twin Cities and Bismarck. It was not based on any studies.<sup>117</sup> Nor is Mr. King's assumption that trees are a primary cause of overhead conductor retirements correct. As Mr. Robison testified:

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<sup>116</sup> Ex. 18, Robison Rebuttal at 15.

<sup>117</sup> *Id.*

In reality, non-preventable damage from storms, ice loading and other non-tree clearance issues are the drivers of retirements for overhead conductors.<sup>118</sup>

Mr. King's assumption that North Dakota weather would support using longer lives for overhead conductors in North Dakota, when compared to Minnesota, is not supported by any studies. In addition, the most recent severe ice storm occurred in North Dakota in 2000, not Minnesota, and the most significant weather related event to harm distribution facilities on Xcel Energy's system was the flooding in 1997 of the Red River in the Fargo area. While a study of North Dakota and Minnesota distribution lives might result in some difference between the two jurisdictions, it would be risky to assume that North Dakota customers would benefit from such a study.

## 5. Conclusion.

The useful lives developed by the Company for production plant and overhead conductors should be approved. Mr. King's life extensions for production plant fail to match the reasonable lives to the investment that is being depreciated. The proposed life extension for overhead conductors is based on a false assumption about the effect of trees on retirements, and the suggestion that North Dakota weather would justify longer lives for overhead conductors is not supported by facts.

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<sup>118</sup> Ex. 18, Robinson Rebuttal at 15.

### C. The Company's Methodology For Recovering Retirement Costs Is Reasonable.

The Company is expected to incur removal costs for all of its production plants and most of its transmission and distribution accounts other than easements and structures. This cost was acknowledged by Mr. King.<sup>119</sup> The Company recovers those retirement costs, which are determined based on the forecasted retirement costs, over the useful life of an asset. Consequently, retirement costs are recovered using the same straight-line principles as is used to recover the initial investment in the depreciation expense. Both the initial investment and the forecasted retirement costs are recovered in equal amounts in each year of the useful life of the asset.

The Company's methodology is used by virtually by all utilities, as Mr. King concedes.<sup>120</sup> It is also used by virtually every State Utility Commission.<sup>121</sup> The Company's methodology is supported by 73 years of traditional and accepted depreciation theory and is fully consistent with accrual accounting principles and regulatory matching principles.<sup>122</sup>

Mr. King proposes taking the Company's forecasted retirement expense and reducing that expense by the amount of inflation included when forecasting the future

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<sup>119</sup> Evidentiary Hearing, Vol. III at 634 (King).

<sup>120</sup> Ex. 23, King Rebuttal at 27.

<sup>121</sup> Our legal research suggests that the methodology used by the Company is approved for use in approximately 44 states.

<sup>122</sup> Ex. 19, Watson Rebuttal at 7.

removal cost.<sup>123</sup> Thus, under Mr. King's proposal, rates would be set to recover the cost of retirement as if the assets are retired during the test year. However, it is undisputed that the assets will be retired at a higher cost in the future. Consequently, the retirement expense that Mr. King would recover in current rates is, by intent, not enough to recover the actual future retirement expense. Because Mr. King did not have the information needed to calculate the present value of the future retirement cost, he instead proposes using the Company's five-year historical average retirement costs to set rates.

Mr. King's methodology is inconsistent with well established accounting principles and shifts current cost responsibility to future customers. The short-term benefit to current customers provided by Mr. King's methodology (the test year reduction is \$455,000<sup>124</sup>) is replaced with a higher cost for future customers. Such a shift in cost responsibility to future customers is inconsistent with accrual accounting principles and regulatory matching principles and should not be adopted.

Company witness Mr. Dane Watson appropriately described Mr. King's method as a form of pay-as-you-go cost recovery, whereas the widely-accepted current methodology complies with accrual accounting principles.<sup>125</sup> While Mr. King argued that his proposal was also an accrual method, the results of his proposal do

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<sup>123</sup> See Evidentiary Hearing, Vol. III, at 671 (King); *and* Ex. 19, Watson Rebuttal at 7.

<sup>124</sup> Ex. 23, King Rebuttal, CWK-7, Schedule 1, page 1.

<sup>125</sup> Ex. 19, Watson Rebuttal at 7.

not support his position. It is beyond debate that the cost of retirements increases over time due to inflation. Thus, it is beyond debate that Mr. King's methodology, which intentionally sets current rates too low to recover the future cost of retirement, is inconsistent with accrual accounting principles.

At the evidentiary hearing, Mr. King argued that his methodology would not require future rates to increase to make up the intentional shortfall, arguing that his methodology provides perpetual savings because, as the Company builds new plants, the new plant retirement cost associated with the replacement plants would, provide "a pot of gold to pay for the [plant] takedown."<sup>126</sup>

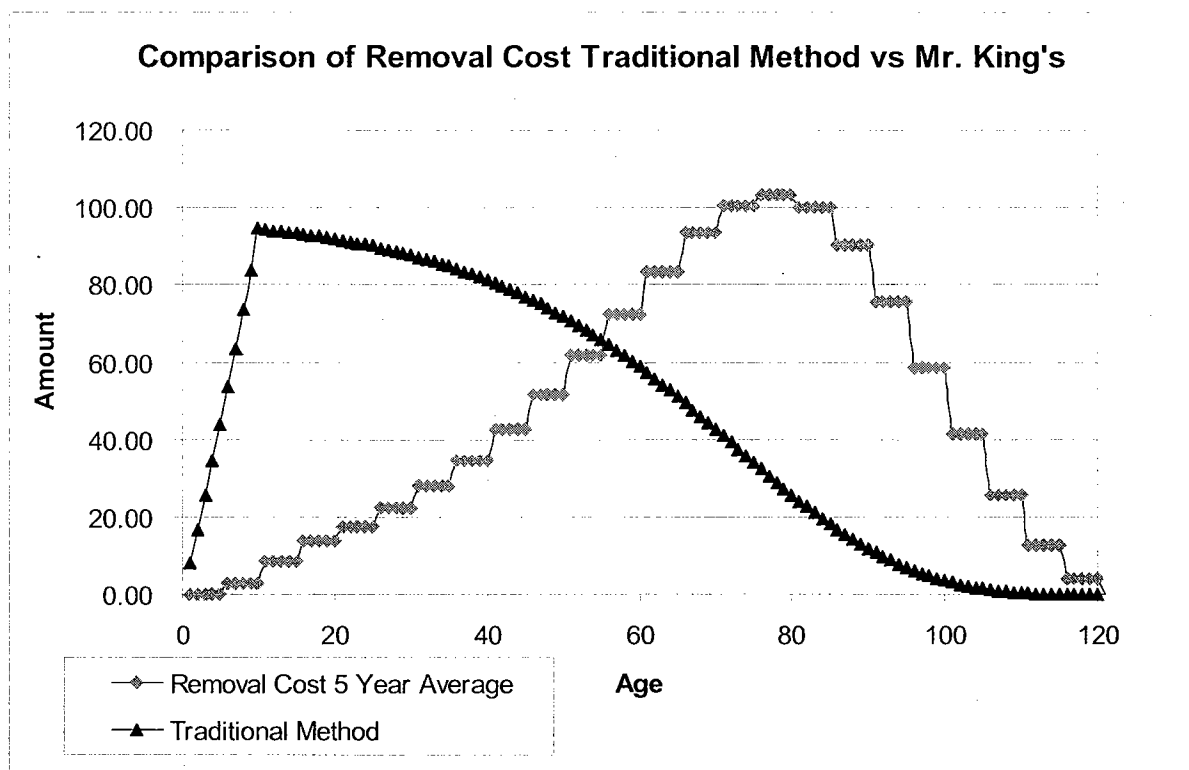
This proposal caused Mr. King's colleague, Mr. Majoros, to return to the stand and explain that, in fact, future customers will be required to pay higher rates in order to make up for the retirement costs that are not paid by prior customers.<sup>127</sup> Exhibit 34, provided by Mr. Majoros, shows that during roughly the first half of an asset's life customers would pay lower rates under Mr. King's methodology (as compared to the Company's widely accepted methodology), and during the second half of the asset's life customers would pay higher rates (as compared to the Company's widely accepted methodology).

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<sup>126</sup> Evidentiary Hearing, Vol. III at 679.

<sup>127</sup> *Id.* at 742-743 (Majoros).

Mr. Watson prepared a more detailed analysis of the same cost shift using an example with ten assets, installed over a ten-year period.<sup>128</sup> Because the assets will have varying useful lives, the Company's methodology recovers more total dollars initially when all of the assets are in use and fewer dollars as the assets retire. In contrast, Mr. King's methodology will recover most of the costs after the majority of the assets have retired. The following chart from Mr. Watson's Rebuttal Testimony compares the costs recovered under the Company's well-accepted method and Mr. King's method:<sup>129</sup>



<sup>128</sup> Ex. 19, Watson Rebuttal at 11-14.

<sup>129</sup> *Id.* at 13.

The Company's method shows a declining cost once all of the assets are installed because, as the assets are retired, the pool of assets against which cost recovery is applied becomes smaller. Mr. Watson's realistic example shows that customers under Mr. King's method will end up paying much higher rates when only a few of the assets remain in service, creating a significant mismatch between benefits and costs.

The pattern created by Mr. King's pay-as-you-go method, which shifts the removal cost to future customers who do not have use of the assets, creates inequity between the current and future generations of customers. Mr. King's recommendation is similar to a balloon mortgage, where customers taking service later in the lives of those assets must make up the shortfall: "Future customers will be forced to pay a disproportionate share of the removal costs of assets that current customers are using."<sup>130</sup>

Mr. Majoros testified that under either methodology customers will pay the same total amount -- it is just the identity of the customers paying the costs that will differ.<sup>131</sup> While that is true in terms of total depreciation dollars paid, it ignores the higher investment costs that would be paid by our customers under Mr. King's proposal. The higher investment cost would occur because of the impact

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<sup>130</sup> *Id.* at 15.

<sup>131</sup> Evidentiary Hearing, Vol. III at 742-743 (Majoros).

depreciation expense has on rate base. As depreciation expense is paid, it is treated as accumulated depreciation, which is an offset to rate base.

Simply stated, the purpose of depreciation is to return investment to the shareholders over the life of the asset, and as the investment is returned, the investment is reduced by the amount of investment returned (depreciation recovered). Because Mr. King's methodology returns a greater portion of the investment later in the asset's life, the offset to rate base is delayed, increasing the return on investment included in rates. Under the example provided by Mr. Watson, customers paid 40 percent more return on investment over the life of the assets under Mr. King's methodology.<sup>132</sup>

Therefore, the Company's methodology for recovering retirement costs should be adopted. It properly aligns costs with benefits, and reduces the overall cost for customers.

**D. The Company Should Not Refund Retirement Costs Paid By Prior Customers.**

Mr. Majoros claims that because the Company has historically recovered retirement costs based on future forecasted retirement cost (rather than based on the present value of those future retirement costs), the Company has "over collected" \$342 million in future retirement funds.<sup>133</sup> Mr. Majoros proposes refunding this "over

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<sup>132</sup> Ex. 19, Watson Rebuttal at 16.

<sup>133</sup> See Evidentiary Hearing, Vol. III at 734 (Majoros).

collection” by amortizing it over a ten-year period in the form of a credit to the depreciation expense. This proposal is premised on the Commission adopting the present value retirement cost recovery methodology discussed in the preceding section of the Brief. However, regardless of the methodology used on a going forward basis to collect retirement costs, the amounts previously recovered will be needed to retire assets in the future, and were authorized under long-standing depreciation policy. There has been no over-collection. Further, there is no basis to credit amounts paid by prior customers to current customers, and any amount credited would have to be recovered from future customers. Consequently, Mr. Majoros’ proposal creates a massive, \$14,500,000, intergenerational mismatch in payments and benefits.

Mr. Majoros speculates that if the Company were deregulated, it might treat the amounts it has collected for future retirement costs as profit instead of as a future liability.<sup>134</sup> To prevent this from happening, he offers two alternatives: (i) treat the \$14,500,000 as a regulatory liability, with a permanent rate base offset; or (ii) credit the “excess” against the depreciation expense at \$1,450,000 per year over a 10 year period.<sup>135</sup>

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<sup>134</sup> Ex. 24, Majoros Direct at 17.

<sup>135</sup> *Id.* at 17 and 21. On a total Company basis, Mr. Majoros claims that the “overcharge” is \$342 million (\$18 million for North Dakota). That, however, would be for both natural gas and electric operations. The actual non-legal ARO for electric service is \$276.4 million. (FERC Form 1 at Pages 204 to 207) <http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=11654315>. The North Dakota allocation of that amount would be approximately \$14.5 million.

The suggestion that deregulation would occur and would change the Company's needs with respect to retiring assets is not credible. The suggestion that retirement costs recovered from past customers pursuant to a Commission approved retirement methodologies should be refunded through a credit to depreciation expenses (only to be recovered again from future customers), would dramatically increase the mismatch between current benefits and costs charged to future customers under Mr. King's present value approach. Requiring the Company to reduce current rates as a result of recalculating the amount of retirement costs the Company would have collected in the past under a present value methodology would also be unlawful retroactive ratemaking.

**1. The Company Will Properly Account For Funds Collected For Future Retirements.**

The Company is required by State and Federal law to retire certain assets, such as nuclear power plants and buildings that contain asbestos. Mr. Majoros does not propose refunding any of the retirement costs held by the company for required retirements (termed "legal" asset retirement obligations or "ARO"). While there is no law that **requires** the Company to retire most of our assets, that fact does not alter the need to retire **all** facilities for which retirement costs are collected. It is not credible to argue that a utility could abandon in place its facilities.

Mr. King, in responding to information requests, agreed that the Company will incur removal costs for all of its transmission and distribution plant accounts, other

than easements and structures.<sup>136</sup> Mr. King and Mr. Majoros further agreed that: “in recent years the cost of removal of most utility plant has come to exceed by wide margins the value of salvage material.”<sup>137</sup> Mr. Majoros also agreed that the Company is entitled to recover all prudently incurred retirement costs.<sup>138</sup>

The fact that the Company recovers from current customers a portion of future costs that will occur because of current service is not unique to retirements, and results from applying normal accrual accounting principles. For example, the Company recovers future costs in this same manner for pensions and other post employment benefit (“OPEB”) expenses.<sup>139</sup> There is no reason to question the propriety of using that same approach for plant retirements, or to single out previously recovered plant retirement costs for a refund.

Mr. Majoros relies heavily on the fact that FAS 143 only requires retirements for AROs and argues that a fundamental change in accounting has occurred, including a change in the treatment of routine plant retirements (“non-legal AROs”). But FAS 143 is merely a financial reporting tool.<sup>140</sup> It is not a regulatory tool. It was not issued

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<sup>136</sup> Evidentiary Hearing, Vol. II at 527 (Majoros).

<sup>137</sup> *Id.* at 528.

<sup>138</sup> *Id.* 542.

<sup>139</sup> *Id.* at 535-536.

<sup>140</sup> Ex. 19, Watson Rebuttal at 21.

by a utility regulatory agency such as the Commission.<sup>141</sup> Nor does FAS 143 require any refunds.<sup>142</sup>

Further, FERC expressly rejected Mr. Majoros' request to change how non-legal AROs are recognized and treated for accounting purposes stating: "we are not convinced that there is a need to fundamentally change accounting concepts at this time."<sup>143</sup> Like FERC, the Commission will determine the regulatory treatment for non-legal AROs within its jurisdiction, and nothing has occurred to justify changing the regulatory treatment of routine plant retirements.

To protect against the Company not retiring assets in the future, Mr. Majoros advocates that the Commission "officially" recognize the amounts previously recovered by the Company for future retirement costs as regulatory liabilities.<sup>144</sup> Mr. Majoros, however, admitted that the Company already treats these amounts as regulatory liabilities.<sup>145</sup> When pressed for the purpose behind his request to make a well established regulatory practice "official," he explained his belief that if the regulatory liability were "officially" recognized, the Company would then be *required* to use a present value approach as advocated by Mr. King, rather than the current future retirement cost approach in determining rates.<sup>146</sup> That issue, however, is already

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<sup>141</sup> Evidentiary Hearing, Vol. II at 533 (Majoros).

<sup>142</sup> *Id.* at 531 (Majoros).

<sup>143</sup> *See* Ex. 19, Watson Rebuttal at 26 (discussing FERC Order 631).

<sup>144</sup> Evidentiary Hearing, Vol. II at 534 (Majoros).

<sup>145</sup> *Id.* at 534.

<sup>146</sup> *Id.* at 539.

directly before the Commission and should be decided on its merits rather than as a byproduct of Mr. Majoros' proposal.

As for the concern that the Company would, if deregulated, not retire assets, the Company in our recent natural gas rate case (Case No. PU-06-525) included the following as an Amendment to the Settlement Agreement:

Should, at any future date, there be change in regulation or other event that would result in a change in the above-described process [for treatment of retirement costs] the Company agrees to work with the Commission to ensure that any accumulated depreciation amounts for retirement purposes are considered and appropriately addressed as part of that change.

The Company reaffirms that offer in this proceeding.

Mr. Majoros also raised these same issues in the most recent natural gas rate case for Public Service Company of Colorado ("PSCo") (Case No 06S-656G). Mr. Majoros' concerns were addressed in a settlement in which PSCo agreed to "include a footnote in its future annual FERC Form 2 filings disclosing the non-legal asset retirement obligation portion of accumulated depreciation for its gas utility operations."<sup>147</sup> The Company is willing to make the same disclosure in our North Dakota Public Utilities Commission Annual Report for our electric operations as well.

These commitments more than adequately address the unrealistic concern that the Company will unilaterally change our accounting for retirements in the future.

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<sup>147</sup> Ex. 19, Watson Rebuttal at 21.

## 2. A Refund Of Previously Collected Retirement Costs Would Be Unreasonable.

Mr. Majoros proposes amortizing (refunding) the revenues the Company previously recovered, but not yet spent, pursuant to the existing Commission approved methodology that recovers retirement costs based on their future cost instead of Mr. King's present value methodology. On a total Company basis, Mr. Majoros claims that \$342 million for both natural gas and electric operations (\$18 million for North Dakota) has been "over collected." The actual non-legal ARO for electric service is \$276.4 million.<sup>148</sup> The North Dakota allocation would be approximately \$14.5 million, to be amortized under Mr. Majoros' proposal at \$1.45 million per year over a ten-year period.

Mr. Majoros presented this proposal for a ten-year amortization in one sentence.<sup>149</sup> He also agreed that, in the alternative, the Commission could leave the previously recovered retirement funds as a rate base reduction.<sup>150</sup> The proposal to reduce current rates by crediting amounts previously collected in accordance with prior Commission authority, only to recover the credited amounts from future customers, would create an even larger inequity between current and future customers than Mr. King's present value proposal. It would also be inappropriate retroactive ratemaking.

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<sup>148</sup> 2007 Xcel Energy FERC Form 1 at pages 204 to 207.

<http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=11654315>

<sup>149</sup> Ex. 24, Majoros Direct at 21.

<sup>150</sup> Evidentiary Hearing, Vol. II at 532 (Majoros).

Mr. Majoros proposes crediting the current depreciation expense with \$1.45 million each year for ten years, for a total credit of \$14.5 million. The \$14.5 million is the North Dakota share of the \$276.4 million in future retirement costs the Company has recovered in prior rates, but not yet spent. Retirement costs are, of course, a cost of providing service, and the \$14.5 million was recovered, in accordance with then existing regulatory practice, as a part of the cost of providing prior service.<sup>151</sup> The \$14.5 million Mr. Majoros proposes to credit would benefit current customers, not the prior customers who actually paid the retirement costs. Thus; a mismatch would be created by the amortization.

An even bigger mismatch and inequity would be created between current and future customers. It is uncontested that the Company is entitled to recover its full retirement costs. Consequently, the full amount credited under Mr. Majoros' proposal would need to be recollected from future customers at the time of the retirements. This would increase the mismatch and inequity between current and future customers that would result from adopting Mr. King's present value methodology by \$14.5 million.

Mr. Majoros asserts that one state, New Jersey, has adopted his proposal, refunding the difference between the five-year average cost of retirements and the retirement costs collected under the previously authorized future cost of retirement

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<sup>151</sup> *Id.* at 529 (Majoros).

methodology.<sup>152</sup> However, a review of that decision indicates that the parties stipulated to using a five-year average methodology for determining retirement costs, and further stipulated to amortizing the difference between that methodology and the amounts recovered under the prior future retirement cost methodology. The New Jersey decision does not discuss the issue and does not address in any manner the intergenerational problems it causes and, as just noted, it was the result of a stipulation.<sup>153</sup> The fact that Mr. Majoros' proposal has only been adopted in one case as a result of a stipulation clearly shows that his proposal is unsupported by established regulatory principles and practices. It is also, for the reasons we have discussed, not in the customers' interest.

Adopting Mr. Majoros' proposal would also violate the prohibition against retroactive ratemaking. It would require the Company to reduce current rates because of funds the Company recovered while implementing prior Commission authorized retirement cost recovery practices. A similar requirement was disallowed in *Montana-Dakota Utilities v Public Service Commission*. In *Montana-Dakota*, the North Dakota Supreme Court reversed a Commission decision reducing a current expense by crediting amounts recovered by the utility under prior Commission approved rates:

When the PSC determines that existing rates are unreasonable, it may only fix or establish new rates to be charged in the future. Section 49-02-03, N.D.C.C; *Quad County Community Action Agency v Elkin*, 315

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<sup>152</sup> *Id.* at 601.

<sup>153</sup> *Re Atlantic City Electric Co.*, ER03020110 (May 26, 2005), 2005 WL 1377887 (N.J.B.P.U.).

N.W.2d 665 (N.D.1982). Prior to these proceedings, MDU's restoration of the ITC to its rate base utilizing a 20-year amortization period was accepted as proper by the PSC. We agree with MDU that the PSC's restatement of the unamortized ITC balance to reflect amortization over a 26-year period constitutes a form of retroactive ratemaking which decreased future rates to compensate for previous higher rates which were based, in part, upon the PSC's initial acceptance of the 20-year ITC amortization period. This the PSC cannot do. We conclude that the PSC, in requiring MDU to change to a 26-year amortization period, can only adjust the amortization schedule of MDU's remaining unamortized ITC balance.<sup>154</sup>

The *Montana-Dakota* decision is directly on point. In both that case and the current proceeding, the utilities had previously recovered expenses by applying Commission approved methodologies. While the Commission has authority to change how expenses are calculated, it would be inappropriate to look backward and declare that expenses recovered under the prior approved methodology resulted in the Company possessing "excess" amounts and to then credit the excess amount against current expenses. Instead the "excess" would continue to be applied as previously authorized. In the current case, the "excess" reduces the amount needed to be recovered in future rates to pay for future retirements, exactly as intended at the time the cost recovery was authorized.

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<sup>154</sup> 431 N.W. 2d 276, 280-281 (N.D.S.Ct. 1988).

### E. Existing Regulatory Practices Concerning Depreciation Studies Should Continue.

Mr. Majoros proposed that the Company be required to file a North Dakota specific depreciation study.<sup>155</sup> In response, Mr. Robinson explained that setting North Dakota specific depreciation rates would create numerous regulatory inconsistencies, and be detrimental to our North Dakota customers and to the Company.<sup>156</sup>

Mr. Robinson explained that, because the Company operates an integrated system, the current methodology for allocating and tracking costs is simple and straightforward. All generation assets, transmission assets, and the vast majority of common and general assets are shared across all jurisdictions.<sup>157</sup>

Using a generating plant as an example, the current practice for setting rates in North Dakota is to use a single depreciation expense calculation. The first step is to allocate the intercompany sharing of this cost between two Xcel Energy Inc. affiliates, NSP-Minnesota and NSP-Wisconsin. The amount allocated to NSP-Minnesota is then allocated to the Minnesota, North Dakota and South Dakota retail jurisdictions, as well as the FERC wholesale jurisdiction based on demand.<sup>158</sup>

If North Dakota were to order different depreciation rates, that process would need to be abandoned. It would be necessary to establish jurisdiction-specific accounting records for depreciation expense and accumulated depreciation to insure

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<sup>155</sup> Ex. 24, Majoros Direct at 7.

<sup>156</sup> Ex. 18, Robinson Rebuttal at 16.

<sup>157</sup> *Id.* at 15-18.

<sup>158</sup> *Id.*

that the appropriate level of depreciation being recovered from North Dakota customers is being properly tracked. As demand percentages change, additional regulatory guidance would be needed to reconcile the inconsistency between jurisdictional specific depreciation rates and system allocated costs.<sup>159</sup>

Before the Commission departs from its long-standing practice of allowing the Company to set depreciation rates on a Company-wide basis, a number of consequences to that decision should be considered. For example, if depreciable lives are set too long in North Dakota relative to the current capital employed, as Mr. King proposes with his life extension adjustments, North Dakota customers will see an immediate rate reduction due to the lower depreciation expense, but at a future cost.<sup>160</sup>

With the slower capital recovery, customers will be required to sponsor higher capital cost and taxes as rate base will decline slower with the longer lives (accumulated depreciation is a reduction to rate base). Then, as the Company makes future capital decisions to either replace the asset or spend the capital required to extend an asset's life, future customers will still be responsible for the un-depreciated value and need to pay costs associated with both the old asset as well as the new asset.<sup>161</sup>

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<sup>159</sup> *Id.*

<sup>160</sup> *Id.*

<sup>161</sup> *Id.* at 16.

In addition, as mentioned above, having a separate depreciation study and North Dakota specific accounting will generate additional North Dakota specific regulatory costs to review the study and implement jurisdiction specific rates.<sup>162</sup>

Further, with the implementation of North Dakota specific depreciation rates, the Company will be required to implement jurisdictional specific accounting to insure that each jurisdictional customer base is equitably treated as to the amount of capital previously recovered and to allow the Company to track the recovery of its capital investments. Such jurisdictional specific accounting would be more costly and burdensome compared to the current process.<sup>163</sup>

The only assertion in the record that North Dakota and Minnesota have different depreciation experiences was made by Mr. King when he speculated that overhead conductors in North Dakota might have longer lives than the overhead conductors in Minnesota.<sup>164</sup> For the reasons discussed earlier in this Brief, there is no support for that position.

In summary, there is no evidence that would justify the additional costs and regulatory burdens on both the Commission and the Company that would result from adopting a North Dakota specific depreciation cost study and review process. In response to concerns raised during our most recent natural gas case (Case No. PU-06-

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<sup>162</sup> *Id.*

<sup>163</sup> *Id.*

<sup>164</sup> Evidentiary Hearing, Vol. III at 702 (King).

525), the Company has provided the Commission all depreciation filings made in Minnesota, and we will address any questions or concerns that those filings may cause.

#### **F. Conclusion.**

The Commission should accept the Company's proposed useful lives for the production plants and overhead conductors. Those lives reflect the engineering analysis of the useful lives of the investment that is being recovered by the depreciation expense. Mr. King's proposal to extend the useful lives in advance of the investment needed to support those life extensions is a mismatch of costs and benefits and shifts the burden of recovering the current investment to future customers after the useful life of that investment has expired.

The Commission should not replace the existing flat rate, future retirement cost recovery with a present value/pay-as-you-go methodology. While the present value method would reduce costs for current customers, the amounts not collected would have to be collected from future customers. Much of the cost would actually be borne by customers who never benefited from the associated assets, causing a severe intergenerational mismatch.

Mr. Majoros' proposal to refund retirement costs previously recovered under the Commission approved future retirement methodology, but not yet spent, would credit \$14.5 million dollars paid by prior customers to current customers, only to require future customers to pay an additional \$14.5 million. This would exacerbate

the mismatch and inequity between generations of customers caused by Mr. King's present-value mechanism and would be improper retroactive ratemaking. To the extent the Commission is concerned that the Company may not actually retire our assets in the future under a deregulation scenario, the Company has proposed imposing two requirements on the Company to address that improbable circumstance.

Finally, the Company recommends that the Commission continue its long-standing approach to depreciation by allowing the Company to utilize a single set of depreciation rates and defer the review of rates and methods to the Company's largest jurisdiction. This process has served North Dakota customers well.

## **V. OTHER FINANCIAL ISSUES.**

As explained below, the Company's proposals regarding the remaining contested financial issues are reasonable and should be accepted. Those issues are: (i) the sharing of wholesale margins (ii) pole inspection and replacement and cable replacement costs; (iii) nuclear refueling outage costs; (iv) nuclear fuel storage costs; (v) charitable contributions; and (vi) incentive compensation.

### **A. The Company Proposed Sharing Of Wholesale Margins Should Be Approved.**

#### **1. Asset-Based Margins.**

There are two types of wholesale margins: asset based and non-asset based.

Asset-based margins result when the Company is able to sell excess energy or capacity

from our generating facilities. The Company proposed paying 85 percent of those margins to customers through the fuel clause and retaining 15 percent as an incentive. The Commission previously authorized a similar incentive mechanism for Montana Dakota Utilities in Case No. PU-399-03-296.<sup>165</sup>

Mr. Majoros recommends that 100 percent of the asset-based margins be passed through the fuel clause.<sup>166</sup> Mr. Majoros' justification is that eliminating the incentive could reduce the fuel costs paid by customers.

However, an effective incentive mechanism can also result in lower customer costs. The Company proposed the incentive to more closely align the interest of shareholders and customers, as we attempt to optimize the use of our generation resources in the wholesale market. Incentive regulation and the accompanying alignment of shareholder and customer interest is an important policy goal and has previously been encouraged by the Commission. However, if the Commission no longer wishes to pursue that policy goal, the Company is willing to adopt Mr. Majoros' recommendation.

## **2. Non-Asset Based Margins.**

Non-asset based trading is the practice of purchasing energy in the wholesale market (other than for retail purposes) and attempting to sell it for a profit. In these transactions, the Company operates as a competitive marketer of wholesale energy,

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<sup>165</sup> Ex. 6, Krug Direct at 2.

<sup>166</sup> Ex. 24, Majoros Direct at 22.

with the potential for economic gains and the risk of losses.<sup>167</sup> In recognition that this is a non-utility activity with significant risk, the Company proposed sharing 15 percent of the margins with the customers through the fuel clause. The 15 percent reflects the fact that there are very few customer supplied costs associated with this activity and, if the activity were discontinued, there would be no material decrease in costs.<sup>168</sup> The Company further proposed that customers only participate in net aggregate gains, not losses, thus ensuring that customers are not harmed by this activity.

Mr. Majoros recommends paying 100 percent of these margins through the fuel clause to the customers. Mr. Majoros' proposal to pay all of the profit from this unregulated business to customers is inconsistent with his goal of keeping rates low.<sup>169</sup>

Non-asset based margins are the result of a voluntary, non-utility enterprise.<sup>170</sup> If the Company is required to pay the entire profit from this risky activity to the customers, with no recovery of losses, there is no reason for the Company to continue the business. A termination of the business would result in no customer benefit. The Company's proposed sharing of 15 percent of the profits from this risky, non-utility business is reasonable and should be adopted. This proposal is also consistent with the Commission's historical support for incentives as an effective regulatory tool.

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<sup>167</sup> Ex. 6, Krug Direct at 12.

<sup>168</sup> Evidentiary Hearing, Vol. II at 489 (Heuer).

<sup>169</sup> *Id.* at 548-549 (Majoros).

<sup>170</sup> Ex. 7, Krug Rebuttal at 3.

**B. The Company's Proposal For Its Pole Inspection And Replacement And Cable Replacement Programs Is Reasonable.**

The Company is requesting that the expenses and investments in the pole inspection and replacement and cable replacement programs be reflected in accordance with the functions and purposes of those expenses and investments. The Company's approach conforms to the proper treatment under the FERC Uniform System of Accounts ("USOA").<sup>171</sup>

In contrast, Mr. Majoros recommends that the Company's expenses and new investment in the pole replacement and cable replacement programs be recorded to a depreciation reserve, which reserve is intended to reflect the cost of *retiring existing* facilities, not the costs of *new investment*.<sup>172</sup> Mr. Majoros did not challenge either the reasonableness of the programs or the level of costs incurred by the Company.<sup>173</sup> The net effect of Mr. Majoros recommendation would be to reduce the Company's revenue requirement by approximately \$128,000.<sup>174</sup>

The Company's proposal should be accepted because the costs are reasonable, and the accounting proposed by the Company accurately reflects both the functions that are being performed and the appropriate accounting treatment under the USOA. The purpose of the inspection and pole and cable replacement programs is to locate poles and cables that need to be replaced and to install new poles and cables as

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<sup>171</sup> Ex. 21A, Heuer Rebuttal at 5.

<sup>172</sup> *Id.* at 3.

<sup>173</sup> *Id.*

<sup>174</sup> *Id.*

necessary to be used in the transmission of electricity over the equipment's useful life. The expense of inspection will be charged to current expenses. The cost of retiring the old poles and cables will be charged to the depreciation reserve. Because the function of the *replacement* of poles and cables will be for the provision of future transmission and distribution of energy, the costs of replacement should be accounted for as an investment in new plant.

The USOA allocates costs into different accounts based upon the nature and type of those different costs. Accounting under the USOA requires that original costs of the electric plant, used by the utility in the electric utility operations, and having an expectation of life in service of more than one year from the date of the installation, be placed into a property account. Sections 101 and 108 of the USOA read as follows:

**101 Electric plant in service**

- A. This account shall include the original cost of electric plant, included in accounts 301 to 399, prescribed herein, owned and used by the utility in the electric utility operations, and having an expectation of life in service of more than one year from the date of installation, including such property owned by the utility but held by nominees.

**108 Accumulated provision for depreciation of electric utility plant**

- .....
- B. At the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost of the property retired and the cost of removal and shall be credited with the salvage value and any other amounts recovered, such as insurance.
- .....

E. *The utility is restricted in its use of the accumulated provision for depreciation to the purposes set forth above. (Emphasis added).*

Account 108 (the depreciation reserve account) is clearly intended to reflect the cost of retirement. In contrast, Account 101 (the plant in service account) is the account in which investments are to be recorded. The Company's proposal conforms to this distinction and treatment. Mr. Majoros proposal violates this distinction and treatment.

The USOA depreciation reserve account is limited to costs associated with the retirement of a depreciable electric utility plant. Mr. Majoros recommends that because poles are being removed, the costs of the *new* poles and cable should be placed in the depreciation reserve. The assignment of costs under the USOA is based upon the purpose of the project, and Mr. Majoros' proposal fundamentally mis-assigns these costs. Mr. Majoros' proposal would also begin to deplete the Company's facility retirement fund for a non-retirement purpose, creating a shortfall in the retirement account.

For these reasons, the Company's request to recover the costs associated with the investment in transmission and distribution infrastructure should be accepted.

**C. The Company's Proposed Nuclear Refueling Outage Costs Are Reasonable.**

The Company is requesting recovery of \$2,319,262 for nuclear refueling expenses. The Company's proposal is based on the normalized expense level under the Commission authorized deferral-and-amortization accounting methodology. This

amount accurately reflects the normalized level of amortized costs for refueling all three plants. Because one of the primary purposes of rate setting is to develop rates that will accurately represent the costs the Company will incur within a typical year, this estimate, which takes into account all of the expected annual costs, should be used in setting rates.

In contrast, Mr. Majoros proposes that the Company's nuclear fuel outage expenses be reduced to \$811,935, based on the non-representative first year of implementing the deferral-and-amortization accounting methodology. As a result, Mr. Majoros' proposal reflects neither: (i) the direct expenses of nuclear refueling in 2008; nor (ii) a normalized level of amortization accounting for such expenses.

In December of 2007, the Company petitioned the Commission for permission to change the accounting method for costs associated with routine nuclear refueling outages because the deferral-and-amortization: (i) provides more stability in costs over time; (ii) more appropriately spreads the expenses over the period that customers receive the benefits of the expenses; and (iii) does a better job of matching revenues with expenses. The Commission approved the change in accounting method in its Order Changing Accounting Treatment in Case No. PU-07-774, but reserved the issue of the proper cost level to be initially recovered for determination in this rate case.

One of the temporary effects of the accounting change is that the expenses during the first year of transition from direct cost accounting to deferral-and-

amortization accounting do not reflect normal cost levels because only nine months of amortization associated with Prairie Island Unit 1, and three months of amortization associated with Prairie Island Unit 2 have been reflected in the first year amortization.<sup>175</sup> Mr. Majoros' recommendation reflects no expense for the Monticello nuclear plant.<sup>176</sup> Consequently, Mr. Majoros' recommendation reflects neither a full year of direct costs nor a full year of amortization and is not representative.

Mr. Majoros admitted that the \$2,319,262 reflected the normalized amount of the future expenses.<sup>177</sup> He also admitted that, starting in 2009, his proposal would result in a shortfall of approximately \$1,500,000 per year for the Company.<sup>178</sup>

Mr. Majoros argued that future costs will fluctuate, and in some years costs will be higher than the test year and in some years they will be lower, so the fact that \$811,935 is below known future costs might be balanced out by lower costs in other programs or years where costs might be lower than expected.<sup>179</sup> However, the possibility of a future reduction in other costs does not justify selecting a cost level for nuclear outage refueling that is clearly below known future cost and, therefore, not representative.

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<sup>175</sup> Ex. 21A, Heuer Rebuttal at 10-11.

<sup>176</sup> *Id.* at 11.

<sup>177</sup> Evidentiary Hearing, Vol. III at 556-558 (Majoros).

<sup>178</sup> *Id.* at 558.

<sup>179</sup> *Id.*

The Company's proposal to use a normalized expense of \$2,319,262 accurately reflects the future amortization costs associated with nuclear refueling outage expenses, and should be accepted.

**D. Private Nuclear Fuel Storage Costs Are Prudent and Should Be Allowed.**

The Company seeks recover of approximately \$190,000 of expenses associated with developing a private nuclear fuel storage facility.<sup>180</sup> The Company's costs associated with the program were accurately determined and prudently incurred, and the Company has developed the facility to the appropriate point at this time.

Operating a nuclear generating facility provides substantial rate benefits to customers in North Dakota. However, one of the costs of operating such a facility is the need to store spent nuclear fuel.<sup>181</sup> Recognizing that the ability to store spent nuclear fuel on site at a nuclear facility is limited (both as to space and after decommissioning of the facility), the Company, along with seven other utility companies, began developing a potential private storage facility.<sup>182</sup>

Mr. Majoros proposes that the Company's private nuclear fuel storage expense be disallowed because: (i) there was no prior approval by the Commission; (ii) he believed that the project is stalled; and (iii) he believed that this project was a

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<sup>180</sup> Ex. 21A, Heuer Rebuttal at 12.

<sup>181</sup> *Id.*

<sup>182</sup> Ex. 13, Bomberger Direct at 24.

Minnesota specific project.<sup>183</sup> Mr. Majoros does not assert that the costs associated with this program were inaccurately determined or imprudently incurred, and he offers no facts that would support such an assertion.<sup>184</sup> Further, he recognizes that spent nuclear fuel has special storage needs and those storage needs will continue after the plant has been decommissioned.<sup>185</sup>

Mr. Majoros identified no Commission policy requiring advance approval of projects as a precondition for cost recovery.<sup>186</sup> He also admitted that he had not realized the Company had obtained the necessary license from the NRC.<sup>187</sup> Having obtained the necessary license, there is no current need for the Company to develop the facility further at this time. In addition, Mr. Majoros was unaware that the Company had seven non-Minnesota utility partners in the project, showing that this was not a Minnesota initiative.<sup>188</sup>

The Company's request to recover \$190,000 in costs for the private nuclear fuel storage facility should be approved because these costs are reasonable and prudent.

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<sup>183</sup> *Id.* at 552 (Majoros).

<sup>184</sup> Ex. 21A, Heuer Rebuttal at 12.

<sup>185</sup> Evidentiary Hearing, Vol. III at 550-551 (Majoros).

<sup>186</sup> *Id.* at 550.

<sup>187</sup> *Id.* at 552.

<sup>188</sup> *Id.*

### **E. Charitable Contributions Serve Customers' Best Interests.**

The Company seeks recovery of one half (\$86,000) of contributions to charities and institutions associated with our electric service territory in North Dakota. Mr. Majoros recommends that the Commission deny any recovery.

The Company has a responsibility to the North Dakota communities we serve to be an active member of those communities and support local economic development and local charities. In 2008, the Company will donate approximately \$165,686 to charitable organizations in North Dakota, of which \$127,567 will be for focus area grants and community grants.<sup>189</sup> Many of these service areas are small communities with fragile economic infrastructures.

Losing customers because people leave the smaller communities as a result of limited opportunities harms all of our North Dakota customers because it decreases revenues and leaves fewer customers to cover fixed costs. In order to combat this risk, the Company uses donations to create economic incentives to allow people to stay in the smaller communities. It is in customers' best interest for the Company to do so.

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<sup>189</sup> Ex. 21, Heuer Rebuttal, at Schedule 2, Page 1.

**F. The Company's Incentive Compensation Proposal Is Reasonably Designed To Provide Market Competitive Compensation.**

The Company requests that the Commission approve our incentive compensation program subject to a cap on the amount that can be recovered in rates set at 25 percent of base pay. Mr. Majoros recommends that the cap on cost recovery be reduced to 15 percent.

The Company's compensation program provides incentives for our employees to focus upon customer service, safety, reliability, cost reductions and other related matters by conditioning receipt of this incentive compensation on the successful accomplishment of goals related to these areas.<sup>190</sup> Without this program, the total compensation that the Company pays to our employees would not be competitive with other similar companies, and the Company would not be able to attract the type of employees necessary to delivery high quality service.<sup>191</sup> The Commission approved a settlement in the Company's natural gas rate case that established a limit of 25 percent,<sup>192</sup> and the Company is simply asking that the Commission set the same limit in this case.

The original justification provided by Mr. Majoros for his proposal was his belief that the Minnesota PUC limited recovery of incentive compensation to 15 percent of salary in the Company's last Minnesota electric rate case. At the

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<sup>190</sup> See Ex. 9, McDaniel Direct at 10-12; Evidentiary Hearing, Vol. I at 182 (McDaniel).

<sup>191</sup> Ex. 9, McDaniel Direct at 9.

<sup>192</sup> Ex. 21A, Heuer Rebuttal at 16.

evidentiary hearings, Mr. Majoros admitted that he was incorrect and amended his Direct Testimony to strike the mistaken reference.<sup>193</sup> However, he did not change his recommendation offering as this sole justification: “these are tough times, why not set a lower limit.”<sup>194</sup> The desire to lower rates is not an appropriate basis upon which to disallow prudently incurred expenses.

Mr. Majoros admitted that he had no evidence to indicate that the Company’s incentive compensation levels are inappropriate, and he offered no criticism of the Company’s incentive compensation levels.<sup>195</sup>

The only rationale that Mr. Majoros could offer was that his recommendation would reduce costs. However, Mr. Majoros admitted that he had no evidence to suggest that the incentive program does not help to accomplish that very goal.<sup>196</sup>

The Company is entitled to recover its prudently incurred costs, and the desire to reduce rates by itself is not an adequate reason for disallowance.

## **VI. THIS PROCEEDING HAS FOSTERED A PRODUCTIVE DIALOG REGARDING THE COMPANY’S RESOURCE PLANNING PROCESS.**

We appreciate the opportunity this rate case presents to have a productive dialog with the Commission regarding resource planning and selection, and we are

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<sup>193</sup> Evidentiary Hearing, Vol. II at 562 (Majoros).

<sup>194</sup> *Id.* at 522.

<sup>195</sup> *Id.* at 562-563.

<sup>196</sup> *Id.* at 603.

committed to improving our resource planning process to more fully address the energy policy interests of North Dakota.

We propose establishing a multi-jurisdictional and collaborative planning process.<sup>197</sup> As we envision that process, meetings between representatives of all State Utility Commissions would occur prior to our filing a resource plan.<sup>198</sup> Such a process would provide a basis to consider and discuss differences between States on a constructive and consistent basis.<sup>199</sup> This process would reflect the type of approach that has been recommended by Commissioner Tony Clark.<sup>200</sup> The Company is also open to considering other approaches, and we propose an initial meeting with Commission Staff to begin developing an appropriate process within 30 days of an Order providing direction for such a process.

While we maintain that the resource decisions incorporated in this rate case are prudent and in the best interests of all customers, including those in North Dakota, we look forward to improving the resource planning process in ways that address the concerns reflected in this rate case proceeding.

The future will include significant financial challenges as the Company faces an era of increasing demand for electricity, constrained energy resources, and increasing environmental challenges. It is critical that the resource planning process provide the

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<sup>197</sup> Ex. 5, Larson Rebuttal at 26-27.

<sup>198</sup> Evidentiary Hearing, Vol. I at 23 (Larson).

<sup>199</sup> Ex. 5, Larson Rebuttal at 27-28.

<sup>200</sup> *Id.*

Company a reasonable basis upon which it can invest with reasonable assurance of future cost recovery.

With adequate financial resources, the Company will be able to invest in generation, transmission, and distribution projects identified and approved through the collaborative resource planning efforts of the Company and State jurisdictions at a reasonable cost. The result would be a win-win situation for all stakeholders.

Forward-looking and collaborative resource planning can lead to improvements as the Company substantially expands its generation resources, including wind generation resources. On the other hand, substantial financial disallowances of prudent resource decisions would seriously impede the Company's ability to maintain an integrated network, or to make future investments at a time when the Company's need for additional generation and transmission facilities is growing rapidly.

We look forward to working with the Commission to develop a workable process for all stakeholders.

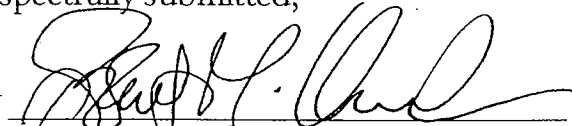
## VII. CONCLUSION.

Based on the foregoing and all the facts in the record, Xcel Energy respectfully request that: (i) we be granted an increase in revenues of \$17.95 million; (ii) that our proposed changes in rate design and tariff provisions be approved; (iii) that our depreciation practices, rates and lives be accepted; and (iv) that our proposal for a cooperative multi-jurisdictional approach to resource planning be approved.

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Respectfully submitted,

By



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