TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES

TO THE

NORTH DAKOTA
PUBLIC SERVICE COMMISSION

SUBMITTED BY
NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION
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Northern States Power Company
North Dakota Ten-Year Plan 2009
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STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE 2009 TEN-YEAR PLAN OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION

TEN-YEAR PLAN

INTRODUCTION

Northern States Power Company, a Minnesota corporation operating in North Dakota[1] ("Xcel Energy", "NSP-M" or the "Company") is pleased to submit our annual Ten-Year Plan to the North Dakota Public Service Commission, in compliance with Section 49-22-04 of the North Dakota Century Code and the Commission's December 31, 2008 Order in Case No. PU-07-776 adopting our rate case settlement.

The Settlement and Order directs Xcel Energy to include in its resource planning an analysis that reflects a North Dakota policy approach to key energy issues. In this Ten-Year Plan, that approach to resource planning is to be comparable to the Company's Resource Plan for the years 2008-2022, which was filed in Minnesota in December 2007 and last updated in February 2009 ("current Resource Plan"). In subsequent cycles of resource planning, the Company is to engage the Commission as it prepares its Plan and incorporate analysis that provides a North Dakota policy perspective. That analysis will be included in our Resource Plan filed in the various

[1] Xcel Energy has service territory in three upper Midwest states including North Dakota. NSP-WI has service territory in Wisconsin and Michigan. The Company presently serves approximately 87,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. Xcel Energy owns approximately 250 miles of transmission lines and 12 substations in North Dakota.

states we serve in so that all Commissions have the benefit of the comparative analysis.

The purpose of the comparative analysis in this Ten-Year Plan is to set the stage for subsequent resource plans. We entered into the current cycle of resource planning in 2007 and updated our analysis last winter. The comparisons we present here are based on planning assumptions and data that now need updating given the changes in the economy and the passage of time that have occurred since our February 2009 update. As a result, the conclusions that can be drawn from the comparisons in this plan are, in some respects, limited. Nonetheless, to begin to understand the impact of North Dakota policy guidance on resource planning, we make these comparisons to the most recent set of analyses. In doing so, we start to identify key assumptions, policy issues, and analyses we need to explore with the Commission as we prepare our next plan.

We are pleased that Commission Staff recently met with us for a two-day session designed to provide a more in-depth look at our Strategist model and resource planning process. The issues are complex and the model is capable of producing much useful information. We appreciate the time and perspectives Commission Staff offered in that session, and we are interested in continuing that exchange.

We hope the Commission and its staff find this plan useful in understanding how we approach resource planning. We look forward to discussing its contents with the Commission, its staff and interested stakeholders to ensure we have adequately reviewed all reasonable options to best meet the needs of our customers both now and in the future.

In addition to the Resource Planning Analysis, this filing contains an expanded Ten-Year Plan submitted in compliance with our rate case Settlement and Commission Rules, including:

- An expanded version of our description of the major generation and transmission initiatives we plan to pursue over the next 5 and 10 years to serve our customers in North Dakota, South Dakota, Minnesota, Wisconsin and Michigan;

- An anticipated schedule of future applications for Advance Determination of Prudence ("ADP") that we plan to file with the Commission; and

- A summary of key energy legislative initiatives enacted in 2008 and 2009 in the states we serve.

SECTION A: RESOURCE PLANNING

OVERVIEW

Xcel Energy's long-term resource planning process evaluates the future resource needs of the NSP system in light of a number of factors, including projected customer energy needs, our current owned and purchased resources, future opportunities and costs for resource development and acquisition, and existing and potential state and federal legal and regulatory requirements. Every two to three years we perform a comprehensive analysis to develop a 15-year plan and a five-year action plan that describes our proposals to cost-effectively and reliably meet our customer needs in North Dakota, South Dakota, Minnesota, Wisconsin and Michigan. Our most recent resource plan was developed in December 2007 and updated in February 2009.

The major elements of the plan include the following:

Upgrade and repower existing resources

Our plan seeks to take advantage of existing plant assets as much as possible. We plan to make efficiency improvements and uprate Unit 3 at our Sherco Generating Facility. We are seeking the necessary approvals to extend the lives of our Monticello and Prairie Island nuclear facilities for an additional 20 years and complete uprates to those units as well. Lastly, we are investigating whether to repower the remaining coal units at the Black Dog Plant with a gas combined cycle unit.

Manitoba Hydro

The Company is working with Manitoba Hydro to extend contracts for major power purchases and exchanges well beyond 2015 when current contracts expire.

Renewables

Our plan includes the acquisition of nearly 2600 MW of wind power over the next 15 years to comply with the renewable energy policies established by the five states we serve. We have proposed two large turn key projects, the 150 MW Merricourt Wind Project and the 200 MW Nobles Wind Project.

Energy Efficiency and Conservation

The plan calls for significant increases in conservation and demand side management to cost effectively reduce energy demand as an alternative to building more new generation.

Natural Gas

The remainder of our resource needs will be met with combined cycle plants and combustion turbines added periodically over the 15-year planning period. We anticipate the first addition will be a 160 MW combustion turbine peaking resource in 2014.

We believe that our current Resource Plan provides a robust resource expansion plan that meets the needs of our customers as well as all of our statutory and regulatory requirements at a reasonable cost. Our plan does not rely on any single technology or fuel and in fact will add at various times new energy and capacity fueled by wind, hydro, coal, gas and nuclear energy. The plan performs well under the broad spectrum of scenarios we analyzed. The plan is particularly well suited to manage the risk of future increases in cost due to potential federal greenhouse gas ("GHG") regulations.

NORTH DAKOTA SCENARIO RESULTS

For this filing we developed a set of resource plan scenarios reflecting North Dakota energy policies and compared these scenarios to our current Resource Plan. In one set of scenarios we applied North Dakota's approach to DSM system wide ("ND Low DSM Scenario"). In another set of scenarios we explored the changes that would result if no additional wind resources were developed beyond current commitments ("ND High DSM Scenario"). We also investigated how a more traditional coal unit might compete with other resource choices in our modeling.

Existing Resources & Manitoba Hydro

Regardless of the scenario visited, our plan to maximize the benefits associated with existing resources remains a preferred option. Extending the life of our nuclear

resources and increasing their production capacity remains cost effective. Extending the life of the Manitoba Hydro contract is also shown to be cost effective. Our analysis indicates that increasing production capacity at Sherco continues to be prudent a enhancement to our system and we are investigating repowering Black Dog Units 3 and 4 as they approach the end of their useful life.

DSM

If applied system wide, North Dakota's level of demand side management would result in much higher energy requirements requiring roughly 2,400 MW of additional generation over the 15-year planning period. By far this is the single most prominent difference between our current Resource Plan and one with a North Dakota policy focus. While our DSM goals – driven by Minnesota requirements and paid for largely by Minnesota customers – are ambitious and results not completely certain, current analysis indicates that our overall plan will be significantly more cost effective if our DSM goals can be achieved.

Renewables vs Gas

After adjusting for the overriding affect of DSM, the next key difference we investigated between a North Dakota policy approach and our current Resource Plan is the substitution of natural gas resources for the proposed wind resources. In this approach, we restrict the addition of wind resources to only those that have been committed to. Then the Strategist model is programmed to select a combination of combined cycle and combustion turbine resources to meet expected demand growth in the most cost effective way possible. The present value of the current Resource Plan (over the 15 year planning period) is just over $200 million more than the natural gas resource scenario, a very small difference of only 0.7%. This cost difference narrows considerably when we assume a higher natural gas cost forecast. The current

Resource plan also emits 31.8 million fewer tons of carbon dioxide over the planning period. As long as any proposed carbon dioxide cost is less than $11.15 per ton, the natural gas alternative would be less expensive given the current gas price forecasts.[2]

Coal

In our analysis we adjusted the cost of a new coal resource by removing carbon sequestration cost estimates. Despite the elimination of carbon dioxide regulatory costs and further renewables development, the Strategist model did not select a new coal plant as a least-cost resource during the planning period. When a coal plant was added to the scenario, the cost differences between the plan containing coal and the lowest cost plan were small but carbon dioxide emissions increased by 6.4 million tons.

Sales Forecasts and DSM

Assumptions about the total energy consumption and peak power demand on our system will drastically influence the cost of electricity to our customers. We will be updating forecasts of customer demand as part of the next resource plan cycle. With the downturn in the economy, our revised base forecasts will be lower than were used in this plan. DSM programs will also serve to lower our forecasts. We will continue to explore how much DSM can be achieved and at what cost.

Renewables

The amount of new wind resources that should be added to our system depends on risk analysis. If one believes federal renewable energy standards and regulations establishing GHG emission limits are in the foreseeable future, our customers are

[2] In earlier communication with Commission staff we presented a lower CO_2 breakeven value for the Merricourt and Nobles Wind projects. The analysis presented here is based on planning assumptions used in our 2008 – 2022 Resource Plan. The Nobles and Merricourt analysis uses updated and project specific information.

going to be better off with additional renewable investments. Renewables also provide an important hedge against natural gas cost volatility. Furthermore, we believe that federal environmental legislation will increase the demand for natural gas.

The investigation of differences in policy approaches has been very enlightening and has served to highlight key issues that will affect the cost effectiveness of our resource portfolio in years to come. We look forward to exploring these issues further with the Commission as we enter the next cycle of our planning.

RESOURCE PLANNING ANALYSIS

We used the Strategist resource planning software to establish the costs of both the ND scenarios and our current Resource Plan. We also considered the impacts of alternative assumptions, such as higher natural gas prices or lower load forecasts, on the costs of both plans. Two of the main outputs of the Strategist model are the chronological list of the existing resource additions ("expansion plan") and the Present Value Revenue Requirements ("PVRR"), which is a measure of the overall cost of the expansion plan in today's dollars. We can use the model to develop the expansion plan with the lowest cost. We can also model the impact on the overall cost, or PVRR, of adding various resources to the plan. By comparing the costs of different plans, we can isolate the impacts of using different assumptions or resources in the model. For additional information about Strategist modeling and the basics of our approach to resource planning, see Appendix B.

A. ND Low DSM Scenario

1. Modeling Assumptions

We designed this ND scenario to meet but not exceed both Federal and North Dakota environmental and renewable requirements for 2008-2022 as they currently

exist. This scenario does not, for example, take into account the potential for GHG pricing under a federal cap and trade plan, or a federal renewable energy standard. To model such a plan, we made changes to the model for our current Resource Plan to remove the requirements for renewable installations, environmental externality costs, demand-side management programs and planning costs for CO_2 emissions that are required by the state of Minnesota.

Specifically, we made the following changes to the model for the current Resource Plan to create ND Low DSM Scenario:

- We eliminated all CO_2 related costs and constraints.
- We removed the partial carbon sequestration component of the 500 MW generic coal plant available for selection by the Strategist model, thus lowering the cost for that potential resource.
- We eliminated all assumptions regarding environmental externality values.
- We limited our wind expansion plan to the amount necessary to meet a 10% renewable energy objective system-wide. Because of the difficulty of selecting wind as a least-cost resource in Strategist, this effectively eliminated all future wind that is not already under contract or specifically committed to be installed in North Dakota from the plan. This reduced the total amount of new wind to be added from 2,260 MW in our current Plan to 400 MW.
- We increased our sales forecast by eliminating the energy savings and respective costs associated with meeting 1.3% of our Minnesota annual retail energy sales through energy conservation activities.

This last assumption (increasing our sales forecast by eliminating energy savings from energy efficiency activities) turns out to be a critical assumption, which we will explore

below. The impacts of this assumption were sufficient enough that we created a second ND scenario (ND High DSM Scenario), which incorporates our current sales forecast, allowing us to make direct comparisons with our current Resource Plan and highlight important resource planning issues between our current Resource Plan and the North Dakota perspective.

2. Comparison Results – Current Resource Plan and ND Low DSM Scenario

a. Expansion Plans

The following table summarizes the least cost resource expansion plans compiled by Strategist to meet our forecast needs under the assumptions established for each planning scenario. This table focuses on the areas of difference between the expansion plans, eliminating the resources the plans have in common such as life extension and capacity uprates of our Prairie Island nuclear generation plant, extension of our supply relationship with Manitoba Hydro, and repowering the remaining units at our Black Dog facility. For additional detail on each expansion plan, see Appendix B.

Table 1. Summary of Expansion Plan Differences

Plan	Combined Cycle Nat Gas (MW)	Combustion Turbine Nat Gas (MW)	Coal (MW)	Wind (MW)	DSM (MW)
Current Resource Plan	1861	320	0	2260	1838
ND Low DSM Scenario	2461	1440	1000	400	0

In evaluating and comparing the resources and costs of our current Resource Plan with those of the ND Low DSM Scenario, it is important to note that the difference

in sales forecasts results in vastly different resource acquisition plans. In total, ND Low DSM Scenario adds 2,469 MW of accreditable resources over and above the current Resource Plan:

- Wind resources are reduced from 2260 MW (305 MW accredited) to 400 MW (54 MW accredited)
- There is a significant increase in the amount of natural gas generation – 600 additional MW of combined cycle resources and 1120 MW of combustion turbine generation.
- 1000 MW of coal generation is added between 2018 and 2020.

b. Cost comparisons

When comparing the overall system costs of these two plans, our current Resource Plan is more cost-effective than the ND Low DSM Scenario. Considering just the direct costs, our current Resource Plan has a lower system cost PVRR than the Low DSM Scenario by more than $1.0 billion over the 15 year plan term.

Table 2. PVRR Cost Comparison – Current Resource Plan & ND Low DSM Scenario

	Current Resource Plan	**ND Low DSM Scenario**	**Difference**
PVRR ($ millions) 2008-2022	$26,883	$27,928	$1,045

Our sensitivity analysis shows that our current Resource Plan has lower costs than the ND Low DSM Scenario in all of the scenarios we examined.

Table 3. PVRR Sensitivity Analysis – Current Resource Plan & ND Low DSM Scenario

ND Low DSM Scenario Sensitivity Analysis - PVRR ($millions) 2008-2022

	Current Resource Plan	ND Low DSM Scenario	Difference
Base Assumptions	$26,883	$27,928	$1,045
Gas + 20%	$27,729	$29,024	$1,295
Gas - 20%	$26,033	$26,827	$794
Coal + 20%	$27,529	$28,686	$1,157
Coal - 20%	$26,239	$27,172	$933
Nuclear + 20%	$27,190	$28,234	$1,044
Nuclear - 20%	$26,577	$27,621	$1,044
Capital Escalation 3%	$26,996	$27,942	$946
Capital Escalation 5%	$26,944	$27,789	$845
High Load	$28,553	$29,952	$1,399
Low Load	$25,273	$28,429	$3,156
MISO On	$26,703	$27,882	$1,179

The cost differences are primarily due to excluding the energy savings from meeting the Minnesota energy efficiency requirements. Excluding these savings increases the forecasted need under the ND Low DSM Scenario, and increases the amount of generation resources that need to be added to the expansion plan by 2,469 MW, thereby increasing overall system costs.

In addition, the ND Low DSM Scenario emitted 68 million more tons of carbon dioxide than our current Resource Plan, which would result in additional higher costs under Federal GHG regulation.

B. ND High DSM Scenario

1. Modeling Assumptions

While the ND Low DSM Scenario is the plan that strictly meets North Dakota requirements, we believe that the Commission will obtain more information from a comparison between our current Resource Plan and a North Dakota scenario that assumes the same sales forecast as our current Resource Plan. The ND High DSM Scenario contains all of the assumptions as listed for the Low DSM Scenario, except that it includes the effects and associated costs of our efficiency investments, resulting in the same sales forecast as our current Resource Plan.

2. Comparison Results – Current Resource Plan and ND High DSM Scenario

a. Expansion Plans

The expansion plan resulting from modeling the ND High DSM Scenario is very similar to our current Resource Plan.

Table 4. Summary of Expansion Plan Differences – Current Resource Plan and ND High DSM Scenario

Plan	Combined Cycle Nat Gas (MW)	Combustion Turbine Nat Gas (MW)	Coal (MW)	Wind (MW)	DSM (MW)
Current Resource Plan	1861	320	0	2260	1838
ND High DSM Scenario	1861	800	0	400	1838

The main difference between the plans is the reduction in planned wind resources by 1,880 MW (254 MW of accredited capacity), which is replaced by 480 MW of natural gas-fired combustion turbines in the North Dakota Scenario.

b. Cost Comparisons

The difference between the direct costs of our current Resource Plan and the ND High DSM Scenario is about $210 million, or about 0.7% of the total PVRR of $26.8 billion.

Table 5. PVRR Cost Comparison – Current Resource Plan & ND High DSM Scenario

	Current Resource Plan	**ND High DSM Scenario**	**Difference**
PVRR ($ millions) 2008-2022	$26,883	$26,673	($210)

A comparison of direct costs reflects only the cost differences due to the resources selected to meet future need. For purposes of this analysis, we excluded all costs related to possible GHG regulation. Our analysis shows under this assumption, implementing the ND High DSM Scenario would result in slightly lower costs over the planning period than the current Resource Plan. These lower costs are consistent throughout most of the sensitivity scenarios, except those where we assume a higher or lower load forecast. When we consider higher natural gas prices or the impacts of market interactions, the cost differences narrow considerably, as shown in the table below:

Table 6. PVRR Sensitivity Analysis – Current Resource Plan & ND High DSM Scenario

ND High DSM Scenario Sensitivity Analysis - PVRR ($millions) 2008-2022

	Current Resource Plan	ND High DSM Scenario	Difference
Base Assumptions	$26,883	$26,673	($210)
Gas + 20%	$27,729	$27,668	($61)
Gas - 20%	$26,033	$25,674	($359)
Coal + 20%	$27,529	$27,367	($162)
Coal - 20%	$26,239	$25,981	($258)
Nuclear + 20%	$27,190	$26,980	($210)
Nuclear - 20%	$26,577	$26,367	($210)
Capital Escalation 3%	$26,996	$26,783	($213)
Capital Escalation 5%	$26,944	$26,735	($209)
High Load	$28,553	$28,560	$7
Low Load	$25,273	$27,161	$1,888
MISO On	$26,703	$26,648	($55)

This analysis shows that the cost difference between the current Resource Plan and the ND High DSM Scenario narrows considerably under a scenario where natural gas prices are higher than forecast. The cost difference is also smaller when we consider the impact of interactions with the MISO market. The "MISO on" scenario reflects our ability to sell additional energy into the market at prices that are above production costs. Incorporating this real world capability into our model shows the cost difference between the two scenarios may, in fact, be negligible.

c. Additional Scenarios

To further highlight and define the differences between the current Resource Plan and the ND High DSM Scenario, we ran two additional sensitivities on this scenario:

- To see the effect that additional wind would have on the plan, we added 400 MW of new wind to the ND High DSM Scenario and evaluated the costs of both with and without a Federal Production Tax Credit ("PTC").
- We noted that although the ND High DSM Scenario excludes the cost of GHG regulations and reduces the cost of the generic coal resource, the expansion plan did not include a coal plant. We therefore added a coal plant in 2018 to evaluate its impact on the direct costs of the ND High DSM scenario.

Wind Addition

Our alternative wind scenario adds 100 MW of wind to the expansion plan in 2015, 2017, 2019 and 2021. Because the Strategist model is limited in its ability to optimize the amount of wind in an expansion plan, adding different amounts of wind allows us to evaluate the relationship between the level of wind in the plan and the resulting PVRR.[3]

We evaluated the wind addition under two different cost assumptions: first, that the PTC was only available through 2015, and second that the PTC would be available throughout the planning period. The second assumption reduces the cost of wind in 2017, 2019 and 2021 by approximately $21/MWh.

Our analysis shows that under an assumption where the PTC ends in 2015, the additional 400 MW of wind increases the PVRR of the ND High DSM Scenario by $72 million. When we assume that the PTC is extended, the additional wind lowers the cost of the Scenario by $20 million.

[3] See Appendix B for additional discussion of modeling wind in Strategist.

The wind analysis shows that different resource choices can, in fact, have relatively small impacts on the costs of a plan. This alternative shows the impact of adding 400 MW more wind. A scenario that added only 100 MW more wind would have a similar but smaller impact on the overall cost. If wind costs are lower (due to either cost improvements or PTC), more wind results in a more cost-effective plan.

Coal Addition

Our current Resource Plan did not select a coal plant at any time over the planning period to meet our projected needs. Coal plants are characterized by high capital costs that allow the conversion of a low cost fuel to electricity. Because of their costs and operating characteristics, coal plants typically run at capacity factors of greater than 80%. In recent plans we have increasingly found that natural gas options or natural gas/wind combinations are selected more often than coal plants.

The absence of a coal plant in our current Resource Plan could be due to a number of factors. The capital costs of coal have increased steeply over the past five years, against somewhat more moderate increases for natural gas-fired facilities. The anticipation of carbon dioxide externality costs also impact the cost of energy from coal. Xcel Energy has also experienced slower off-peak load growth than on-peak growth, reducing our need for new around-the-clock energy facilities. Energy from wind additions further reduces our energy needs in the off peak hours, and natural gas resource options provide for more flexible dispatch than coal facilities.

The ND High DSM Scenario, which utilizes the same sales forecast as our current Resource Plan, also did not select a coal plant as a resource. To isolate the cost and operational differences between a plan that includes a coal facility and a similar plan that does not, we added a coal plant in 2018 to the ND High DSM Scenario, creating

a Coal Scenario. We then compared the resulting costs to the ND High DSM Scenario:

Table 7. Coal Scenario PVRR Sensitivity Analysis

Coal Scenario Sensitivity Analysis - PVRR ($millions) 2008-2022			
	ND High DSM Scenario	**Coal 2018 Scenario**	**Difference**
Base Assumptions	$26,673	$26,689	$16
Gas + 20%	$27,668	$27,602	($66)
Gas - 20%	$25,674	$25,773	$99
Coal + 20%	$27,367	$27,406	$38
Coal - 20%	$25,981	$25,974	($6)
Nuclear + 20%	$26,980	$26,996	$16
Nuclear - 20%	$26,367	$26,383	$16
Capital Escalation 3%	$26,783	$26,768	($15)
Capital Escalation 5%	$26,735	$26,729	($6)
High Load	$28,560	$28,560	$0
Low Load	$25,761	$25,815	$55
MISO On	$26,648	$26,646	($1)

Like the wind scenario, the coal scenario demonstrates how there can be very similar costs between expansion plans that contain very different resources. The PVRR of the Coal Scenario is only $16 million higher than the ND High DSM Scenario. In the sensitivities where we assume that natural gas costs are higher or coal costs are lower, the Coal Scenario has a lower PVRR than the ND High DSM Scenario. Once again, this scenario demonstrates that the modeling does not provide compelling evidence of a single, optimal resource plan; rather there are a number of options that can be pursued with very similar costs.

In comparing these two scenarios, we need to evaluate the risks as well as the costs. If we compare only the direct costs of the plans, either may appear to be reasonable. On further assessment, however, the potential GHG costs associated with the Coal Scenario make that plan riskier than the base plan. Similarly, the Coal Scenario looks better under an assumption of no GHG regulation but high natural gas prices. A balance of these considerations would likely lead us to select the base plan due to the high probability we assign to GHC regulation.

C. Robustness of Our Current Resource Plan

Resource Planning is sometimes referred to as "Least-cost Planning." Certainly one goal of developing a resource plan is to minimize costs under a wide variety of potential outcomes. There are other important goals, however, that lead to a robust and workable plan best suited to meet our customers' needs. In addition to cost, a good resource plan should manage a number of risks inherent in an unknown future, and provide for flexibility that will allow us to revisit and update our plans as that future becomes known.

As we weigh these issues, we continue to believe that our current Resource Plan and associated Five-Year Action Plan remain appropriate, as it will provide a robust, cost-effective, and flexible set of resources to meet our customers' needs for reliable service. Specifically, compared to the ND scenarios, our plan should:

- Result in lower or comparable overall system costs,
- Provide a hedge against natural gas price volatility, and
- Manage risks associated with future regulation of CO_2 emissions.

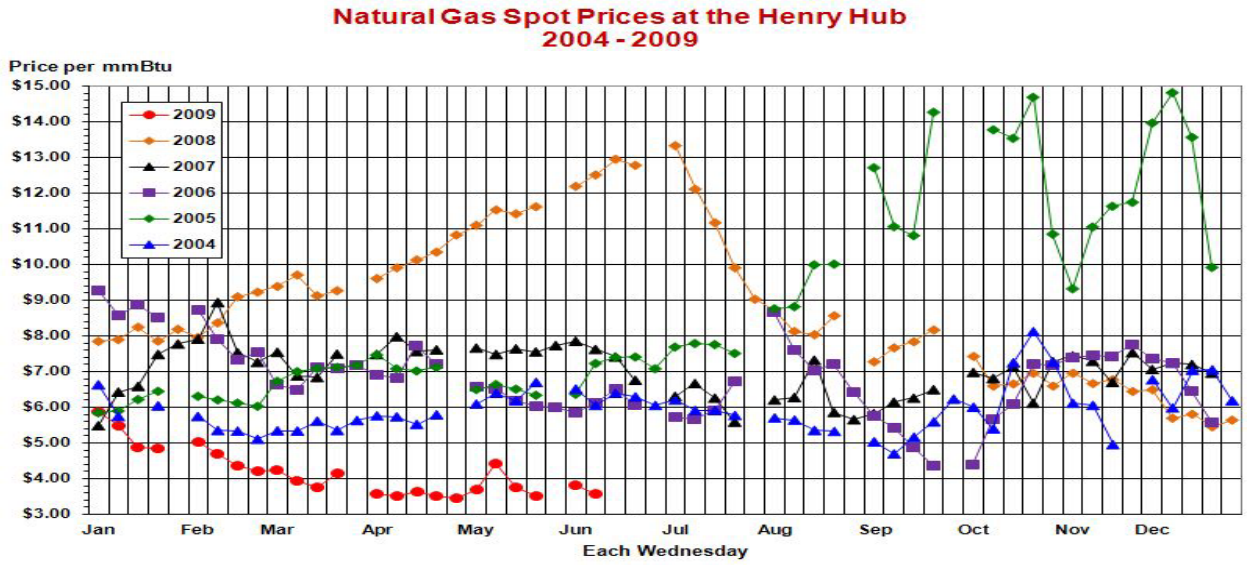
Hedge against natural gas price volatility

As noted above, one of the major differences between our current Resource Plan and the ND High DSM Scenario is that the latter relies more heavily on new natural gas generation resources. This increased reliance results from the significant reduction in wind resources in comparison to our current Resource Plan.

Our experience with pricing wind generation resources over the past several years is that it is very similar to the cost of natural gas generation. Very small changes in assumptions such as natural gas prices, wind costs, capacity factors and integration costs will change the cost relationship between the two. Other assumptions such as the continued availability of the PTC or the inclusion of GHG regulation costs will result in larger shifts.

The cost similarity between natural gas and wind highlights another the need to fully assess the risks when determining the best resources to add to our portfolio. Natural gas generation facilities are dispatchable but they can be subject to volatile fuel costs, as shown in the following figure.

Figure 1. Natural Gas Pricing Volatility at the Henry Hub



Source: *Natural Gas Weekly Update*. Energy Information Administration, Washington, DC; Nebraska Energy Office, Lincoln, NE

Wind projects, on the other hand, are intermittent. Although the costs to integrate and follow them on the system need to be considered, wind resources have no fuel costs and no emissions. Wind resource costs are therefore much more certain at the time of acquisition. By choosing to rely more heavily on wind resources in our service areas in combination with natural gas generation, we are able to manage risks associated with natural gas fuel pricing volatility and provide price certainty to our customers.

Manage risks associated with future regulation of CO_2 emissions

The issue of global climate change is in the forefront of public policy debate in the United States. Congress and the Obama Administration appears poised to enact legislation to limit CO_2 emissions. Global climate change and the likelihood of future GHG regulation underlie the approach proposed in our resource plan. We believe that, by the time we file our next resource plan in 2010, the nation will be subject to

regulations designed to reduce GHG emissions, and that those regulations will have a significant impact on the Company's operations.

Estimating and incorporating in our planning the future costs of CO_2 regulation allows us to compare resource plans with higher direct costs but lower CO_2 emissions against lower cost resource plans that emit more CO_2, and gauge their relative impact on overall system costs.

For example, suppose we have the ability to add either a natural gas resource or a wind resource to meet a particular energy need. If the direct cost of the natural gas option is $60.00/MWh and the direct cost of the wind option is $63.00/MWh, the Strategist model will likely add natural gas instead of wind if other assumptions are the same. Including a CO_2 planning cost of $20/ton increases the natural gas option cost by over $8.00/MWh and would cause the model to select wind instead. The direct cost of the wind is $3.00/MWh higher than the "least cost" option, but it potentially avoids $8.00/MWh in CO_2 costs. If GHG regulation is not implemented, customers pay $3.00 more; but if it is, they pay $5.00 less.

The additional cost of the wind resource relative to the carbon dioxide-emitting natural gas resource can be thought of, in essence, as an insurance premium against potential higher costs of GHG regulation. The size of the premium that customers are willing to pay depends on the probability of GHG legislation and the magnitude of that potential cost differential.

As discussed above, the difference in direct costs between our current Resource Plan and ND High DSM Scenario is between $55 and $210 million over the planning period. While our current Resource Plan has higher direct costs, it also has lower

GHG emissions than ND High DSM Scenario. The difference in CO_2 emissions between the two plans is 31.8 million tons. Table 8 below shows the impact to the two plans cost differences from potential future GHG regulation.

Table 8. Summary of GHG Cost Impacts

Present Value of GHG Cost Impacts Based on a Difference of 31.8 million tons	
	PV $millions
$5/ton	$94.19
$10/ton	$188.38
$15/ton	$282.57
$20/ton	$376.76

As can be seen in the table above, the cost difference between the two plans is eliminated when GHG regulation costs of between $10 and $15/ton start in 2012 and escalate at 2.5%. At an $11.15/ton CO_2 regulation cost, the two plans are equal cost.

Note that our analysis of the potential for future GHG regulation is a risk assessment relating to a potential legislative action and not intended to be an evaluation of an environmental externality. Externalities are the costs and benefits that a generating facility may impose on the socioeconomic and natural environments that are not paid for or captured by the generation owner. Examples of classic externalities include the impact of acid rain on fish populations or the potential health impacts of particulate emissions. The consideration of these costs in resource planning may result in the selection of a higher cost plan that reduces the impacts of the externality, but there is no probability that customers will ever pay for the actual cost of the externality itself.

In contrast, the GHG cost analysis considers the potential internal cost of climate change legislation, similar to the costs we might incur to purchase SO_2 allowances or install pollution control equipment on our plants. The costs of GHG regulation, if implemented, will directly impact rates and increase the costs of GHG emitting resources.

Our current Resource Plan contemplates resource additions that will be in place for 30 to 50 years or longer. When we consider whether to add such resources, it is reasonable and necessary to evaluate not only the known and direct costs, but also the potential for future costs. Companies and regulators alike need to understand the relationship between the costs and risks of GHG-emitting resources and discuss the appropriate balance between the two.

The ND High DSM Scenario results in a lower cost plan when considering only the direct costs of the resources.[4] When GHG regulatory costs are considered, however, the cost difference is reduced or eliminated. Consideration of potential CO_2 costs in our planning today allows us the ability to choose to avoid those costs in the future.

Other Environmental Costs

In addition to GHG regulations, other federal environmental regulations are pending that would also raise the costs of our resource plans. Pending Federal mercury regulation may result in plant mercury standards that are at least as stringent as our current requirements under the Minnesota Mercury Reduction Act, and will result in retrofit costs at all of our plants that emit mercury. Evaluating the costs and risks associated with pending mercury legislation has a large impact on the various options we are evaluating for our Black Dog coal-fired generating plant, which is near the end

[4] As noted in the analysis, the ND Low DSM Scenario results in a higher cost plan than our current Resource Plan under all sensitivities.

of its life. Currently, our plan to repower the plant as a natural gas-fired combined cycle appears to cost less than retrofitting the plant for mercury regulation and continuing to operate it on coal. As with all of our new resource proposals, these costs and options will be thoroughly analyzed before proposing a project for approval..

Impact of Capital Sensitivity

The outcome of our resource plan is also dependent upon the capital costs of the various resources available to meet our needs. In recent years, we have seen a significant escalation in the cost of new resources. New coal facilities, which contain more concrete and steel than natural gas facilities, have increased so much that (as shown in the ND High DSM Scenario) they are not considered least cost resources even when the cost of GHG regulation is not considered.

Similarly, a recent 20% increase in wind capital costs have led to a change in the relationship between wind and natural gas facilities: where in our 2007 Resource Plan filing wind was the most cost effective option, our current analyses show that even when considering a \$17 CO_2 cost, wind is slightly more expensive than natural gas. While some of that cost difference depends on the forecasted price of natural gas, the capital costs of gas plants versus wind plants also plays a role.

With the recent economic downturn, we are seeing a slight softening in prices for new generating resources. We are continuing to evaluate that trend, and will incorporate our updated data in our next resource plan.

D. Modularity and Flexibility

The conditions under which we and the rest of the energy industry operate are rapidly changing. Load forecasts, fuel forecasts and capital costs change far more rapidly

than they did in the previous century, and changes in the global economy have large impacts on our resource plan. Between our 2007 Resource Plan filing and our February 2009 update, we eliminated 480 MW of proposed natural gas-fired peaking generation and delayed proposed Sherco upgrades and our Black Dog repowering for at least two years. This was largely a result of a reduction in our load forecast due to the economic downturn. Our next resource plan, to be filed in 2010, will likely show additional impacts from the downturn.

Rapidly changing conditions call for plans that are flexible and modular. As conditions change, resources may need to be resized, canceled, added, delayed or advanced to ensure that we maintain a reliable, adequate and reasonably priced energy supply for our customers. Currently, our ability to use demand-side management, market purchases, modular wind and gas facilities, and pursue upgrades and life extensions at our current facilities provide us with greater flexibility to match our load forecast than does committing to the construction of large facilities such as coal plants with long lead times, high capital costs and major environmental risks. Our current Resource Plan provides a flexible resource expansion plan that can be easily modified to meet changing conditions.

E. Ongoing Discussion

As we discussed in our introduction, this analysis is intended to be a starting point for increasing our understanding of the Commission's perspectives and enhancing the Commission's participation in our resource planning process. It provides a comparison to our 2007 filing. While the data is due to be updated in our 2010 filing, the comparison we have done in this Ten-Year Plan provides a baseline for future resource plan evaluations.

Resource planning is an iterative process. Although we plan for a 15-year period, we focus primarily on the five-year action plan: those actions that we need to undertake in the near term to keep our resource plan on track. Through periodic comprehensive updates and minor adjustments as circumstances change, we are continuously reviewing and renewing our plan.

These regular plan updates provide the opportunity for an ongoing dialogue with our regulators and stakeholders on the shape and direction of the resource planning process. Resources are frequently included in two or more resource plans before we petition for their regulatory approval. Early discussion of our resource choices leads to better plans, as we are provided with new information and viewpoints to consider and challenged to look critically at the choices we are proposing. This dialogue is in fact the key benefit of resource planning; it allows for feedback and modification of our plans prior to the point when resource implementation decisions are imminent and options are considerably narrowed.

We look forward to a regular and ongoing discussion with the Commission regarding our Resource Plans. At the Commission's direction, in future Periodic Information Exchange ("PIE") meetings or other venues we propose to bring additional information to further illuminate our plans and processes. For example, we can provide further exploration and analysis around specific issues such as resource capital costs, natural gas pricing and trends, GHG regulatory costs, and the costs and benefits of wind energy and other issues as the Commission may desire.

CONCLUSION

We believe our current Resource Plan addresses the key issues facing the Company and hope that this report provides the Commission and its staff with a better

understanding of our resource planning process and current Resource Plan. Implementation of our current Resource Plan will allow us to maintain a portfolio of robust, flexible, and diverse resources, reduce our exposure to future government regulation of GHG emissions, manage significant costs and risks, and maintain reliable service at reasonable rates.

We hope the Commission and its staff finds this analysis to be useful in understanding how we approach resource planning. We look forward to discussing this with you further, as well as to get your advice and input as to how we can make this analysis more useful to you in the future, including specific resources or scenarios the Commission would like us to consider.

As part of the Settlement Agreement in our 2007 North Dakota electric rate case, we agreed to:

1) provide an update of our 2007 Resource Plan Five Year Action plan, which includes a summary of the key generating and transmission investments or purchase agreements that we intend to construct or enter into within the next 5 years; and

2) an anticipated schedule of future applications for Advance Determination of Prudence that we commit to filing with the Commission.

SECTION B: FIVE YEAR ACTION PLAN

Our five-year action plan is provided below. Summaries of individual components of this plan can be found in Section E.

Generation

- Obtain federal and state approvals for additional dry cask storage to operate out to 2034 and power uprates at our Prairie Island (164 MW) and Monticello (70 MW) Nuclear Generating Plants.
- Pursue investments at our Sherco 3 coal-fired unit to increase capacity by 20 MW.
- Compete our analysis and establish a plan to repower Black Dog Units 3&4 as cost effectively as possible.
- Complete negotiations with Manitoba Hydro for an extension to existing contracts under new term sheets and seek regulatory approvals as needed.

- Obtain regulatory approvals and complete construction of the 200 MW Nobles and 150 MW Merricourt Wind Projects in 2010 and 2011, respectively.
- Finalize our plans for an additional 50 MW of wind located in North Dakota, and seek regulatory approvals as needed.
- Complete our commitment to purchasing 500 MW of community based wind resource projects in Minnesota.
- Obtain regulatory approvals for converting our Bay Front plant's Unit #5 (20 MW) in Wisconsin to biomass gasification technology and complete construction by 2012.

Transmission

- Obtain routing approvals for the following CapX2020 Group 1 345 kV lines and construct those lines:
    - A 250 mile, 345 kilovolt line between Fargo, North Dakota, and Alexandria, St. Cloud and Monticello, Minnesota.
    - A 230 mile, 345 kilovolt line between Brookings, South Dakota, and Hampton, Minnesota, southeast of the Twin Cities, plus a related 30-mile, 345 kilovolt line between Marshall, Minnesota, and Granite Falls, Minnesota.
    - A 150 mile, 345 kilovolt line between Hampton, Minnesota, Rochester, Minnesota, and LaCrosse, Wisconsin.
- Obtain regulatory approvals for the final CapX2020 Group 1 line, a 68 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota
- Complete Midwest Independent Transmission System Operator ("MISO") interconnection study process for approximately 20 miles of new 230 kV transmission for the Merricourt Wind Project. Final transmission

infrastructure needed, ownership structure and cost estimates will be determined through that process.

- Pursue regulatory approvals for the Greater Rochester Area Transmission Project.

SECTION C: SCHEDULE OF ADVANCE DETERMINATION OF PRUDENCE FILINGS.

The following tables identify those projects for which we intend to seek an ADP finding from the Commission, along with a page number in this Plan where a description of the proposed project can be found.

Pending ADP petitions

Project	Date Filed	Docket Number	Description (page number)
Merricourt Wind Project	12/3/08	PU-08-908	38
Nobles Wind Project	12/3/08	PU-08-907	38
Bay Front Biomass Gasification Project	5/27/09	PU-09-216	39

Upcoming ADP petitions

Project	Expected Filing Date	Description (page number)
CapX2020 Group 1 Transmission Lines	July 2009	42
Monticello Nuclear Generating Station Extended Power Uprate and Prairie Island Nuclear Generating Station Extended Power Uprate & License Extension	October 2009	34

Possible ADP petitions – timing and certainty of project moving forward dependent on outcome of resource planning process and other key decisions

Project	Description (page number)
50 MW of North Dakota wind	38
Black Dog Repowering	36
Community Based wind project PPAs	39
Manitoba Hydro PPA	37

SECTION D: EXISTING ENERGY CONVERSION FACILITIES

While the Company does not currently own energy conversion facilities in the State of North Dakota, the Company has power purchase agreements with power plants located in North Dakota. Minnkota Power Cooperative, Inc. provides the Company 100 MW each summer season from its rights in the Coyote #1 coal fired steam generating unit located in Beulah, North Dakota. Acciona Wind Energy USA provides the Company with 12 MW of wind energy from turbines located near Velva, North Dakota. Additionally, the Company has a transmission service agreement known as the "Stanton Displacement Agreement" in which 188 MW are supplied from Great River Energy's Stanton Unit, located in the vicinity of Stanton, North Dakota, for the Company's North Dakota loads.

SECTION E: PROPOSED ENERGY CONVERSION FACILITIES - NEXT FIVE YEARS

NSP-M and Northern States Power Company, a Wisconsin corporation ("NSP-W"), operate their upper midwest generation resources on a five-state integrated system basis (North Dakota, South Dakota, Minnesota, Wisconsin and Michigan). We identify our resource needs in our Resource Plan, the most recent of which was filed with the Minnesota Public Utilities Commission ("MPUC") on December 14, 2007, (Docket No. E002/RP-07-1572) and provided to the Commission shortly thereafter. As stated in our 2007 Resource Plan, we propose to continue to fulfill our future electric generating resource needs through multiple resource acquisition processes including competitive bidding, Company ownership and power purchase agreements. This multipronged and flexible approach to resource acquisition allows us to consider multiple technologies and locations.

In this section, we update the Commission on generation projects that were included our 2008 Ten-Year Plan, and provide a summary of the generation projects we are considering or undertaking in the next five years across our five-state integrated system. We believe these projects, taken as a whole with our existing generation assets, result in a robust and diverse portfolio of resources that will provide our customers with cost-effective and reliable service over the long-term.

NUCLEAR RESOURCES

Monticello: On January 8, 2009, the MPUC issued an order granting a Certificate of Need for an extended power uprate at our Monticello Nuclear Generating Station (MPUC Docket No. E002/CN-08-185). This power uprate will result in 68 MW of additional base load capacity and associated energy. We expect to receive approval from the federal Nuclear Regulatory Commission for amendments to the plant's operating license to accommodate the uprate in January of 2010. We plan to begin the necessary retrofits for the uprate during the 2009 refueling outage, and complete them by 2011. We plan to request for an Advance Determination of Prudence finding for this project in the fall of 2009.

Prairie Island: On May 16, 2008, we filed applications with the MPUC for two Certificates of Need involving our Prairie Island nuclear generating plant. MPUC Docket No. E002/CN-509 would provide for an extended power uprate of 164 MW at Prairie Island. Docket No. E002/CN08-510 would allow additional dry cask spent fuel storage to support extending operation of the two Prairie Island units through 2033/2034. Both proceedings have been referred to an Administrative Law Judge who will develop and evaluate the record and forward recommendations to the MPUC. We anticipate MPUC action in both proceedings by the end of 2009. A

MPUC Order approving the additional dry cask spent fuel storage would be stayed until July 1, 2010 to allow the Minnesota Legislature time to evaluate the decision and provide further direction if it deems necessary. In addition, both projects require NRC approval. We plan to request an Advance Determination of Prudence finding for this project in the fall of 2009.

FOSSIL FUEL RESOURCES

Sherco Upgrades: As discussed in the 2007 Resource Plan, we are proceeding with upgrades at our Sherburne County ("Sherco") Generating Facility. Initially, the Sherco upgrades would have involved investments at all three units at Sherco, and would have resulted in up to 80 MW of additional base load capacity as well as significant updates to pollution control systems. At this time, however, we are proceeding only with the capacity addition at Sherco 3, as well as the installation of a mercury control system at that unit. The total capacity increase of this upgrade will be approximately 20 MW, of which the Company's share will be 12 MW.

Our plans for Sherco 1 and 2 projects were much broader in scope than the Sherco 3 upgrade, increasing the capacity of those units by approximately 70 MW, and would have cost more than $1 billion. After initial engineering work, a review of the current economic climate and our current load growth scenarios, we concluded that it would be prudent to delay the projects at Sherco 1 and 2.

Peaking Resource: In our 2008 Ten-Year Plan, we stated that we were in the final stages of conducting our due diligence on 160 MW of peaking generation. The 2011 peaking resource need was identified and approved in our 2004 Resource Plan (MPUC Docket No. E002/RP-04-1752), and reconfirmed in our December 2007 Resource Plan filing. However, recent updates to our demand and energy forecasts

have indicated a significant reduction in our projected growth rates. This reduction in load growth, coupled with lower planning reserve requirements established by the MISO Planning Reserve Sharing Group, has eliminated the need for this facility in the next five years. Based on this conclusion, we have discontinued our negotiations for a 2011 facility. We will continue to monitor our load forecast and reevaluate the need for additional peaking facilities in our next Resource Plan.

Black Dog Repowering: As we noted in appendix B of the Resource Plan and Acquisition Update we filed with the MPUC on February 9, 2009, we have been studying repowering the remaining coal facilities (units 3 and 4, together about 270 MW) at the Black Dog facility. Black Dog units 3 and 4 were installed in 1955 and 1960 respectively and are currently near the end of their economic and engineering life. We estimate that by approximately 2015 we will either need to retire these units or make substantial investments, including significant environmental improvements necessary to meet federal emissions standards, to extend their lives. Analysis of a number of options including life extension showed that repowering units 3 and 4 with a natural gas combined cycle facility at the same site would be a cost-effective option. During 2008, we hired engineering consultants to develop the costs and schedules for a 700-750 MW potential project to be in service in 2015. However, as the economic downturn continues to impact our load forecast, we are developing and analyzing additional project and resource options, including a later in-service date for the conversion, repowering in phases, or purchasing demand and energy from a third party. We will update the Commission as soon as our plans become clearer, and will file for an Advance Determination of Prudence finding if we decide to move ahead with this project.

Rehabilitation and Repowering: We have completed the rehabilitation and repowering of the Allen S. King plant located in Stillwater, Minnesota; the Riverside plant located in Minneapolis, Minnesota; and the High Bridge plant located in St. Paul, Minnesota. All three plants are now back in operation. These projects increased Company-owned generating capacity by just over 400 MW.

OTHER SYSTEM RESOURCES

Manitoba Hydro: We are continuing to negotiate a contract with Manitoba Hydro to implement an agreed-upon term sheet for a 10-year purchase of 375 MW of capacity with "5x16" (five days a week, 16 hours a day) energy starting in 2015. This resource is a replacement for our current 500 MW purchase from Manitoba Hydro. The term sheet also extends our 350 MW diversity exchange with Manitoba Hydro through 2025.

Since the term sheet was signed, the Midwest Reliability Organization has adopted new resource adequacy requirements that are somewhat different than the standards previously used in MAPP to accredit capacity. We have been working with MISO and Manitoba Hydro to ensure that the capacity under the new agreements can be used to meet our capacity obligations and reserve margins. We have recently extended the term sheet to August 31, 2009. We expect to come to an agreement with Manitoba Hydro and initiate an ADP docket before the Commission some time in 2009.

RENEWABLE RESOURCES

In our 2008 Ten-Year Plan, we discussed our commitment to construct or purchase at least 200 MW of wind power resources in North Dakota. As the Commission is

aware, we have selected the Merricourt Wind Project to satisfy 150 MW of this commitment, and are seeking opportunities for the additional 50 MW.

Merricourt Wind Project: The Merricourt Wind Project is a 150 MW wind energy generation facility consisting of 100 GE 1.5 MW wind turbines located within a project site encompassing approximately 9,600 acres in McIntosh and Dickey Counties in North Dakota. We have entered into a build/transfer agreement with the wind development company enXco to develop the facility. Primary construction on the Merricourt Wind Farm will occur in Spring of 2011, and we anticipate that commercial operation will be achieved by December 2011. On December 3, 2008, we applied to the Commission for a Certificate of Public Convenience and Necessity and an Advanced Determination of Prudence for the Merricourt Wind Project. (Case Nos. PU-08-908 and PU-08-910)

50 MW Wind Project: We propose to acquire an additional 50 MW of wind in North Dakota either through ownership or a purchased power agreement, to be operational by the end of 2012. We have been evaluating options and propose to issue an RFP for the 50 MW in the latter half of this year. If all 50 MW are part of a single project, as we expect they will be, we will file for an Advanced Determination of Prudence for these 50 MW of North Dakota wind when that becomes appropriate.

Nobles Wind Project: The Nobles Wind Project is a 201 MW wind energy generation facility consisting of 134 GE 1.5 MW wind turbines located in Nobles County on the Buffalo Ridge in Minnesota. We have entered into a similar build/transfer agreement with enXco for the Nobles Wind Project as we did for the Merricourt project. We expect the Nobles Wind Project to begin commercial operation by December 2010. The request for an Advanced Determination of

Prudence for this project was also filed on December 3, 2008 (Case No. PU-08-907) and is pending before the Commission.

Grand Meadow: On December 24, 2007, the MPUC issued a Certificate of Need in MPUC Docket No. E002/CN-07-873 for a Company-owned 100 MW wind farm (Grand Meadow) to be constructed near Austin, Minnesota. The Grand Meadow project was developed by enXco and constructed by Mortenson Construction in 2008. In December 2008 the wind farm became fully operational and project ownership was transferred to Xcel Energy.

Community Based Wind: The Company also plans to acquire 500 MW of Community Based Renewable Energy Resources by 2010. We have about 79.9 MW of Community Based wind projects currently operational, and another 64.4 MW under contract and scheduled for construction. In January of 2009, we issued a request for proposals for additional community based wind projects that could be operational by the end of 2010. We received 45 proposals totaling 2229 MW by the RFP deadline of February 20, 2009. We are currently evaluating those proposals on a number of criteria, including price and transmission availability and will issue a short list of potential projects shortly.

Bay Front: On May 26, 2009, we filed a request for an ADP (Case No. PU-09-216) for Commission consideration of our proposal to install biomass gasification technology at our Bay Front Power Plant in Ashland, Wisconsin. If approved, the project will convert the plant's remaining coal-fired unit to biomass gasification technology, allowing us to use biomass in all three boilers at Bay Front and making it the largest biomass plant in the Midwest. Currently, two of the three operating units at Bay Front use biomass as their primary fuel to generate electricity.

The project, estimated at $58.1 million, will require additional biomass receiving and handling facilities at the plant, an external gasifier, minor modifications to the plant's remaining coal-fired boiler and an enhanced air quality control system. Burning the gasified biomass will decrease the amount of electric generating capacity of the third unit from approximately 28 MW currently to an estimated 20 MW. However, we will still have the capability to use natural gas for peaking purposes and retain the 28 MW of accredited capacity.

This project provides a unique opportunity to increase the fuel diversity and dispatchability of our renewable generation fleet, hedge against future environmental regulations, and help manage natural gas volatility, while continuing to use infrastructure already in place at the facility. The project is planned to go into service in 2012.

SECTION F. PROPOSED ENERGY CONVERSION FACILITIES - NEXT TEN YEARS

At this time, the only plans that we have for additional generation facilities in the State of North Dakota in the next ten years may be for wind energy conversion systems. The exact size and location(s) of such facilities are yet to be determined.

SECTION G. EXISTING ELECTRIC TRANSMISSION FACILITIES

Xcel Energy's existing electric transmission line facilities are listed below. Xcel Energy has no plans to retire any electric transmission facilities in North Dakota within the next ten years.

Table 9. Xcel Energy North Dakota Transmission Lines

Northern States Power Company
North Dakota Transmission Lines

State	Description	Functional Unit	Voltage	Line Miles
	230 kV Lines			
ND	Maple River (Minnkota)	0910	230 kV	3.60
ND	Maple River (Minnkota)	0911	230 kV	8.00
ND	Drayton (Minnkota)	0912	230 kV	28.70
ND	Sheyenne-Fargo	0915	230 kV	4.30
ND	Prairie (Minnkota)	0916	230 kV	6.60
ND	Manitoba Hydro Inter (Glenboro)	0920	230 kV	56.32
	Total 230 kV			**107.52**
	115 kV Lines			
ND	Maple River-Sheyenne	0839	115 kV	11.70
ND	Souris-Neal	0850	115 kV	26.00
ND	Mallard-Souris	0860	115 kV	5.30
ND	Cass County-Sheyenne	0866	115 kV	5.00
ND	Prairie-Nordic1	5510	115 kV	2.00
ND	Prairie-Nordic2	5511	115 kV	2.10
	Total 115 kV			**52.10**
	69 kV Lines			
ND	Minnkota-Prairie	0733	69 kV	46.37
ND	Prairie-Grand Forks	0746	69 kV	6.30
ND	South-Hatton	0768	69 kV	28.60
ND	Prairie-Minnkota	0772	69 kV	13.30
ND	Elk Valley-Larimore	0776	69 kV	1.70
ND	Grand Forks (WAPA)	0786	69 kV	10.16
	Total 69 kV			**106.43**

SECTION H. EXISTING PIPELINE FACILITIES

Xcel Energy operates an 11.9-mile intrastate natural gas pipeline facility in the State of North Dakota, from an interconnection with Williston Basin Interstate Pipeline Company near Mapleton, North Dakota to the Company's gas distribution system in Fargo. The Commission granted a Certificate of Public Convenience and Necessity and Corridor Certificate for this facility in Case No. PU-400-89-426. Xcel Energy has no plans to retire any intrastate natural gas pipeline facilities in North Dakota within the next ten years.

SECTION I. PROPOSED ELECTRIC TRANSMISSION FACILITIES - NEXT FIVE YEARS

In this section, we provide a brief description of significant transmission developments planned by the Company in North Dakota and elsewhere in the NSP service territory.

CapX 2020: In 2005, a group of investor-owned, cooperative and municipal utilities in eastern North Dakota, Minnesota, eastern South Dakota, and western Wisconsin, completed a high-level visionary study looking at the bulk transmission needs in their combined market areas over the next 15 years. Among other things this analysis, known as CapX 2020, identified the possible need for one or two 345 kV lines from western North Dakota to the Twin Cities. One of the lines proposed would pass through the Fargo area to serve growing energy needs in the Red River Valley.

From this vision study the CapX 2020 utilities developed more specific proposals for the first group of new high voltage lines needed, referred to as Group 1 projects. The

Group 1 projects include three 345 kV projects, and one 230 kV project. The approximate lengths and general location of the proposed lines are as follows:

- A 250 mile, 345 kilovolt line between Fargo, North Dakota, and Alexandria, St. Cloud and Monticello, Minnesota.
- A 230 mile, 345 kilovolt line between Brookings, South Dakota, and Hampton, Minnesota, southeast of the Twin Cities, plus a related 30-mile, 345 kilovolt line between Marshall, Minnesota, and Granite Falls, Minnesota.
- A 150 mile, 345 kilovolt line between Hampton, Minnesota, Rochester, Minnesota, and LaCrosse, Wisconsin.
- A 68 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota

On April 16, 2009, the MPUC approved Certificate of Need applications submitted by Xcel Energy and Great River Energy for the three 345 kV projects identified above. (MPUC Docket No. ET2, E002/CN-06-1115). To address concerns raised by the Minnesota Office of Energy Security and other intervenors as to whether the capacity of the proposed lines would be adequate, the MPUC required that all three 345 kV lines be "double-circuit ready", i.e. constructed in such a way as to facilitate adding a second 345 kV line on the same set of transmission towers (the Lyon Co-Franklin-Helena section of the Brookings -Hampton 345 kV line was already proposed as a double circuit line). The three 345 kV lines are proposed to be in-service between 2011 and 2015.

The MPUC has yet to decide on the lines' routes. Route Permit applications currently are under state review or in development; decisions are expected in 2010 and 2011, depending on the project.

A portion of the proposed Fargo - Twin Cities 345 kV project would be constructed in North Dakota. The CapX 2020 participants anticipate filing for a Certificate of Public Convenience and Necessity application in late 2009. We anticipate filing the North Dakota Corridor Compatibility and Route Permit Applications at that time as well.

A Certificate of Need application for the 68 mile 230 kV project was filed with the MPUC on March 17, 2008, in MPUC Docket No. E017, E015, ET6/CN-07-1222. Even though it will be constructed entirely in Minnesota, this project has the potential to substantially improve load serving capability in the northeastern part of North Dakota. The 230 kV project is proposed to be in service between 2011 and 2012.

The CapX 2020 Group 1 projects will benefit North Dakota by improving transmission infrastructure and reliability, alleviating existing delivery constraints, and expanding the transmission capability to allow expanded generation investment, including wind generation, in North Dakota.

More information about the CapX 2020 initiative is available at www.capx2020.com.

Buffalo Ridge Incremental Generation Outlet (BRIGO) Transmission Project: In September 2007, we received a Certificate of need from the MPUC to add three 115 kV transmission lines in SW Minnesota. This is known as the BRIGO transmission project:

- Lake Yankton Substation to a new substation near Marshall, Minnesota (Southwest Marshall) -15 Miles.
- Fenton substation to Nobles County substation -23Miles.

- Yankee substation- Brookings County (South Dakota) substation -6.5 Miles.

The purpose of these transmission facilities is to improve reliability to the growing City of Marshall load and to increase the level of wind generation outlet from the Buffalo Ridge of Minnesota and South Dakota by 350 MW. These projects will be completed by the end of 2009.

Chisago- Apple River Transmission Project: In February 2008, we received a certificate of need from the MPUC to construct a 115/161 kV line from the Chisago County substation to just east of St. Croix Falls, Wisconsin where it will interconnect with a new Dairyland Power Cooperative 161 kV line from Apple River. This joint project is to provide reliable power to north central Wisconsin and the far north Twin Cities suburbs. This project is scheduled to be completed in 2011.

South West Twin Cities 115 kV Conversion: This project involves rebuilding a 20 mile and an 18 mile section of existing 69 kV to 115 kV between Glencoe and Waconia substations and Scott County and Westgate substations in the southwest suburbs of the Twin Cities. This is required due to load growth in these outer ring suburbs of the twin cities. A certificate of need is expected to be filed in late 2009. This project is expected to be completed in 2012.

Merricourt Interconnection: The Merricourt Wind project is planned in the vicinity of Ellendale, North Dakota. It will interconnect with the Montana-Dakota Utilities transmission facilities. This will require additional transmission infrastructure. This project is presently proceeding through the MISO interconnection study process. The final transmission infrastructure needed, ownership structure and cost estimates will be determined through that process. Initial results indicate this will require

approximately 20 miles of new 230 kV transmission lines as well as additional investments to other facilities in the area.

Greater Rochester Area Transmission Project: This project, also known as the Pleasant Valley area projects, is a proposal to construct two 161 kV lines in the greater Rochester area:

- Pleasant Valley to Byron substation (18 miles)
- Pleasant Valley to Willow Creek substation (25 miles)

These projects are required to allow for the development of additional wind generation in southeast Minnesota.

There is a number of wind projects proposed in this area and at various stages within the MISO Interconnection study process. The MISO studies for Xcel Energy's Grand Meadow project and the Wapsipinicon Wind farm determined that interconnecting these projects would cause transmission system constraints and would require the Pleasant Valley-Byron 161 kV line. Until this new upgrade is constructed, the wind projects are sometimes limited in the amount of power they can deliver to the system. Adding wind in this area will require the additional projects.

SECTION J: PROPOSED PIPELINE FACILITIES - NEXT FIVE YEARS

At this time we do not have plans to construct any new intrastate natural gas pipeline transmission facilities in North Dakota within the next five years.

SECTION K: PROPOSED ELECTRIC TRANSMISSION AND PIPELINE FACILITIES - NEXT TEN YEARS

In addition to the CapX2020 group of utilities, Xcel Energy participates in transmission planning with a larger group of utilities called the Minnesota Transmission Owners. The MTO consists of all of the investor-owned, cooperative and municipal utilities that own transmission facilities 115 kV and above in Minnesota. Several MTO members (the Company, Great River Energy, Otter Tail Power, etc.) also own significant transmission in North Dakota. These utilities are required by Minnesota law to file a biennial transmission plan with the Minnesota commission by November 1 of every odd-numbered year, and formed the MTO to develop and submit a unified plan. The MTO has commissioned a number of studies focused on meeting renewable energy objectives and requirements and other generation and load serving needs through 2025. These are comprehensive studies encompassing the impacts and needs over more than just Minnesota. These MTO studies are available at the MTO website at: www.minnelectrictrans.com.

As a result of two recent studies, the MTO has identified an additional project that it believes is necessary to meet regional reliability and generation outlet needs within the next 10 years:

Upgrade Existing Minnesota Valley to Blue Lake 230 kV line: This project, otherwise known as the "Corridor Upgrade", would replace the existing 230 kV line between the Blue Lake Substation in Shakopee, Minnesota and the Minnesota Valley Substation near Granite Falls, Minnesota with a double-circuited 345 kV line, continued to the new Hazel Creek substation south of Granite Falls, Minnesota. This upgrade would provide significant new transmission capacity from the Dakotas,

southwestern Minnesota and western Minnesota to the Twin Cities, at an estimated cost of $350 million. The Corridor Upgrade would provide an increase in generation delivery from the Dakotas and the Buffalo Ridge on the order of 2000 MW. The project will also serve to enhance system reliability by backing up the CapX Brookings SD to Twin Cities 345 kV line. The MTO believes this project should be the next transmission project pursued after the CapX2020 Group 1 lines.

At this time, we do not foresee the need for any new intrastate natural gas pipeline transmission facilities in North Dakota in the next ten years.

SECTION L: REGIONAL COORDINATION

All major transmission planning performed by Xcel Energy is now coordinated through MISO on a regional basis, consistent with the Federal Energy Regulatory Commission ("FERC") orders dated: (a) May 2000, authorizing the transfer of functional control of the Company's high voltage transmission system to MISO; (b) December 2001 finding MISO to be the first FERC-approved regional transmission organization ("RTO"); and February 15, 2007 (Order No. 890), requiring RTOs and their member utilities to use coordinated regional transmission planning.[5] MISO issues an annual MISO Transmission Expansion Plan ("MTEP") after coordinated planning and stakeholder review.

MISO is continuing the use of the existing subregional planning groups of the Mid-Continent Area Power Pool ("MAPP"), which coordinate the planning of the utilities

[5] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890"), *order on reh'g*, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2008) (Order No. 890-A); *order on reh'g* 123 FERC ¶ 61,299 (Order No. 890B) (June 23, 2008). MISO's Order No. 890 regional transmission planning process was conditionally accepted for filing in *Midwest Independent Transmission System Operator, Inc.*, 123 FERC ¶ 61,164 (May 15, 2008).

within the MAPP region. This coordination applies to all NSP-M facilities in North Dakota, South Dakota, and Minnesota and NSP-W facilities in Wisconsin and Michigan.[6] As a result of complying with the FERC Order No. 890 rules, MISO has also implemented its own Sub-Regional Planning Meetings. The Company participates in the Western Region meetings. MISO coordinates these meetings with the Northern MAPP Sub-regional Planning Group ("SPG") meetings. Both of these groups provide forums for stakeholder input and coordination of plans and NSP-M actively participates in each one. This joint planning is intended to maximize use of existing facilities and minimize the amount of new facilities. Additional regional planning coordination is provided by the Dakotas-Montana Power Suppliers Group.

Another example of coordination by the utilities is the formalization of the MTO organization. In addition to the Minnesota biennial transmission planning work of the MTO, the MTO utilities also coordinate their transmission planning activities with the CapX2020 planning processes, the MAPP SPG processes and MISO's MTEP process.

The MTO also coordinated and performed two major transmission studies. The Dispersed Renewable Generation Transmission Study investigated the potential to install 600 MW of dispersed renewable generation in and around Minnesota with minimal impacts to the transmission system. The other study was a series of studies under the heading of Renewable Energy Standard transmission studies that

[6] NSP-M and NSP-W are members of MAPP, which continues to provide certain planning functions; and the Midwest Reliability Organization ("MRO"), which provides certain Regional Reliability Coordination ("RRC") functions required by the North American Electric Reliability Council ("NERC") and previously provided by MAPP. NSP-M and NSP-W are also participants in the Midwest Contingency Reserve Sharing Group Agreement ("Midwest CRSGA") administered by MISO. NSP-M and NSP-W withdrew from the MAPP Generation Reserve Sharing Pool ("MAPP GRSP") effective June 1, 2008. NSP-M and NSP-W have also given notice of formal withdrawal from MAPP that will be effective April 15, 2011. NSP-M and NSP-W now participate directly in the Midwest CRSGA rather than indirectly through the MAPP GRSP.

investigated the short and long-range transmission requirements in Minnesota and North and South Dakota for the MTO utilities to meet the Minnesota RES.

Xcel Energy is also actively supporting the on-going work of the Upper Midwest Transmission Development Initiative ("UMTDI"). Formed in September 2008 by the Governors of North Dakota, South Dakota, Iowa, Minnesota and Wisconsin, the goal of the UMTDI is, in coordination with MISO, to:

1. identify key wind generation resource zones within these Upper Midwest states, as well as the transmission projects and infrastructure needed to develop those resources in a cost-effective manner; and
2. develop reasonable cost allocation criteria for the transmission projects identified.

An executive committee made up of a representative of the Governor's office from each state and a regulatory commission from each state was formed to plan and implement a work plan focused on these two areas. Activities to address both areas of the UMTDI work plan are underway, and the UMTDI executive committee plans to submit recommendations to the five Governors by the fall of 2009.

SECTION M: ENVIRONMENTAL INFORMATION

Specific environmental information will be provided to the Commission in future regulatory filings when specific facilities are identified for construction.

SECTION N: PROJECTED DEMAND FOR SERVICE

NSP-M and NSP-W operate an integrated electric generation and transmission system (the "NSP System") serving customers in North Dakota, South Dakota, Minnesota, Wisconsin and Michigan. The North Dakota portion of the NSP System 25-year historical native energy requirements and non-coincident peak demand are shown in Table 10. Xcel Energy produces long-range "median" NSP System forecasts of native energy requirements, summer peak, and winter peak demand. For planning purposes, Xcel Energy also develops a bandwidth to supplement its "median" forecasts. These scenarios are intended to describe uncertainty in a business-as-usual context: a relatively narrow range of U.S. economic growth with no basic change in the relationship between the regional and national economies. Table 11 shows the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the NSP System. Table 12 shows the North Dakota portion of the NSP System forecast.

The forecast for the NSP System is based on forecasts of jurisdictional sales by major customer class: residential with and without space heating, small commercial and industrial ("SC&I"), and large commercial and industrial ("LC&I"). Each customer class is modeled independently for the five states included in the NSP system. The native energy requirements are determined by applying a loss factor on total sales.

The NSP System peak is apportioned to jurisdictions based on the native energy requirements by state and the load factor by state. Consequently, the summer and winter "peak loads" provided in Table 12 represent the North Dakota jurisdiction customer demand at time of the NSP System seasonal peak demand. This "coincident" demand is appropriate for generating capacity requirement forecasting.

It is important to note, however, that a "non-coincident" peak demand must be used in evaluating transmission capacity requirements. This is because the transmission system must be able to supply the full local customer demand at all times. Due to load diversity caused by weather variations within the multi-state NSP System, peak customer demands in Xcel Energy's North Dakota service areas can be as much as 25 percent higher than the demands registered during the hour in which the total system peak demand occurs. It is these local "non-coincident" peak demands that determine the need for transmission improvements required for load serving functions.

Table 10. Historical Energy and Peak Load Requirements (1980 - 2008) North Dakota portion of NSP System

Year	Energy (GWh)	Annual Growth	Non-Coincident Peak Load (MW)	Annual Growth
1980	1,237	---	267	---
1981	1,265	2.3%	295	10.5%
1982	1,369	8.2%	275	-6.8%
1983	1,441	5.3%	308	12.0%
1984	1,484	3.0%	303	-1.6%
1985	1,544	4.0%	322	6.3%
1986	1,553	0.6%	311	-3.4%
1987	1,553	0.0%	312	0.3%
1988	1,658	6.8%	323	3.5%
1989	1,844	11.2%	374	15.8%
1990	1,904	3.3%	399	6.7%
1991	1,925	1.1%	373	-6.5%
1992	1,883	-2.2%	376	0.8%
1993	1,771	-5.9%	333	-11.4%
1994	1,796	1.4%	360	8.1%
1995	1,916	6.7%	362	0.6%
1996	1,984	3.5%	382	5.5%
1997	1,911	-3.7%	351	-8.1%
1998	1,958	2.5%	352	0.3%
1999	1,950	-0.4%	363	3.1%
2000	2,053	5.3%	370	1.9%
2001	2,048	-0.2%	384	3.9%
2002	2,119	3.5%	403	4.8%
2003	2,171	2.4%	395	-2.0%
2004	2,158	-0.6%	403	2.2%
2005	2,289	6.1%	426	5.7%
2006	2,353	2.8%	439	3.0%
2007	2,378	1.1%	463	5.5%
2008	2,478	4.2%	427	-7.8%

Table 11. Forecast of NSP System Energy and Peak Load Requirements (2009 - 2027)

Year	Energy (GWh)	Summer Net Peak Load (MW)	Winter Net Peak Load (MW)
2009	47,062	9,399	7,107
2010	46,882	9,411	7,115
2011	47,305	9,456	7,142
2012	47,762	9,506	7,167
2013	48,193	9,562	7,188
2014	48,657	9,610	7,213
2015	49,066	9,665	7,238
2016	49,508	9,727	7,258
2017	49,923	9,784	7,272
2018	50,408	9,830	7,286
2019	50,762	9,863	7,292
2020	51,194	9,896	7,290
2021	51,587	9,909	7,284
2022	52,021	9,917	7,279
2023	52,362	9,925	7,269
2024	52,844	9,991	7,310
2025	53,342	10,068	7,355
2026	53,931	10,145	7,406
2027	54,398	10,231	7,456
Average Annual Growth Rate, 2009-2027:			
% growth:	**0.8%**	**0.5%**	**0.3%**

Notes:
1) Peak Load is ***coincident*** to the NSP System peak.
2). Winter Peak = MAPP Winter Peak season, 2009 is 2009 - 2010 winter peak.
3) Peak Load is the Net Peak (interruptible)

Table 12. Forecast of Energy and Peak Load Requirements (2009 - 2027) North Dakota Portion of NSP System

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2009	2,442	323	409
2010	2,465	327	414
2011	2,495	331	417
2012	2,531	334	420
2013	2,566	338	423
2014	2,604	343	426
2015	2,632	347	428
2016	2,663	350	431
2017	2,693	353	432
2018	2,727	357	434
2019	2,751	361	437
2020	2,778	365	440
2021	2,803	369	443
2022	2,832	374	446
2023	2,854	378	449
2024	2,879	382	451
2025	2,903	386	454
2026	2,931	391	457
2027	2,950	395	461
Average Annual Growth Rates, 2008-2026:			
% Growth:	**1.0%**	**1.1%**	**0.7%**

Notes: 1). Peak Load is ***coincident*** to the Xcel Energy system peak.
2). Winter Peak = MAPP Winter Peak season, 2009 is 2009 - 2010 winter peak.
3.) Peak Load forecast growth from 2019 - 2027 is based on average summer and winter ND peak growth rates from 2009 - 2018.

APPENDIX A
Legislative Update

The following tables provide a summary of key energy provisions enacted in North Dakota, South Dakota, Minnesota, Michigan, and Wisconsin in 2008-2009.

North Dakota

Year	Provision	Description
2009	SB2033 – Income Tax Credit for wind, geothermal, solar or biomass energy devices	Allows any excess income tax credits earned for wind energy devices installed between January 1, 2009 and January 1, 2012, to be carried forward for up to twenty taxable years. This Act is effective for taxable years beginning after December 31, 2008.
	SB2032 – Sales & Use tax exemption on materials used for construction or expansion of wind-powered facility	Extends the sunset date for an exemption from sales and use tax for materials used in construction or expansion of wind-powered, and certain other renewable, generation facilities to January 1, 2015. This legislation will become effective on June 30, 2009.

	SB2031 – Taxable valuation of centrally assessed wind turbine electric generators	Extends the property tax reduction for centrally assessed wind turbines with a generation capacity of 100 kW or more and construction occurring between June 30, 2006, and January 1, 2011, until January 1, 2015. The unit will be valued at 1½ percent of assessed value to determine taxable valuation of the property. Wind turbines constructed after January 1, 2015, will be taxed at the 10 percent rate, the same as all other commercial property in the state. This legislation will become law on August 1, 2009.
	SB2443 – Facility relocation cost recovery due to implementation of the American Recovery and Reinvestment Act of 2009	Prevents the costs of facility relocation caused by implementation of the American Recovery and Reinvestment Act of 2009 from being passed on to utility customers. This Act is effective through July 31, 2011. This legislation will become law on August 1, 2009.
	HB 1032 – Energy conversion and transmission facility siting	Allows a utility company that holds a valid certificate or permit to construct additional facilities at that location without a full environment siting process. Rather, a company must certify to the PSC that any new project complies with the siting act and all existing permits and conditions. Further, the bill contains special provisions for building near or on pre-1975 sites that were not subject to the siting act.

	HB1509 – Requirements for wind easements and leases	Establishes a number of requirements for wind easement contracts. The bill also requires the Legislative Council to consider studying wind easements and leases during the interim.
	HB1449 – Decommissioning of wind energy conversion facilities	Builds on existing PSC rules for decommissioning, by setting forth additional requirements to be addressed such as present and future natural resource development; and the location of any portion of underground foundation that was not removed must be recorded with the appropriate county recorder. This bill also reduced the current siting threshold for generating facilities from 100 megawatts to those exceeding 60 megawatts. The Legislative Council shall study the development of wind resources and other natural resources in the same location, and also review of laws relating to siting and decommissioning during the interim.
	HB 1322 – Create permanent Energy Policy Commission	Establishes an Energy Policy Commission, to which the Governor will appoint all representatives. The commission will be chaired by the Commissioner of Commerce. All sectors of energy are representative of this commission. This is a re-authorization and renaming of the EmPower Commission created by the 2007 Legislative Session.

	HB 2137 – Powers of the PSC and electric and gas public utility application fees	Calls for sizeable application fees to accompany significant filings ($125K for rate applications and ADP filings, $50K for environmental and transmission cost recovery rider filings) to the PSC for purposes of funding PSC expenses during the case. Bill allows for the PSC to waive or adjust the fees downward if appropriate.
	SB2245 – Wind easements and leases	Tightens the five-year window for wind easements and leases causing the agreements to be void and terminate unless significant progress has taken place on the project i.e., permits issued, transmission interconnection request in process, etc.
	SCR4015 – Study the economic impacts of proposed federal, regional, and state carbon cap and trade systems, including the Minnesota Next Generation Energy Act of 2007	Directs the Industrial Commission to study the economic impacts of all carbon cap and trade systems as well as the Minnesota Next Generation Energy Act of 2007.

	HCR3044 – Study the allocation of wind rights	Requires an interim study of property rights of all persons in and near wind farms. It is expected this study will address correlative rights of all property owners in or near wind farms. It is anticipated that this study may also address setbacks of towers from property lines as well as the "unitization" of wind farms.
	SB2060 – Utility Infrastructure in Renassance Zones	Allows utility companies that install new infrastructure in renaissance zones to participate in the same property and income tax breaks as other property owners in the zone.
	SB2297 – Gross Receipts and Property Tax reform	Rewrites the method of gross receipts taxes paid by RECs from a straight tax upon gross receipts to a formula that now also includes energy sales. There is also an "opt-in" provision for shareholder owned companies should they wish to make a change from centrally assessed, ad valorem property taxation before October 2012.

South Dakota

Year	Provision	Description
2008	HB 1123 – Renewable Energy Objective	Creates a renewable energy "objective" that 10% of our customers' energy needs will be provided with renewables by the year 2015.

	SB 40 – Investor-owned utilities with non-regulated subsidiaries	Placed "ring fencing" rules in statute that more clearly limit the separation between an investor-owned utility and its non regulated subsidiaries.
	HB 1320 – Wind farm taxation	Enacts an annual tax based on nameplate capacity and gross receipts.
2009	SB 57 – Conserved energy resources	Amends the 2008 REO bill to allow "conserved energy sources" to be included in the list of energy sources that would count toward the 10% REO by 2015.
	SB 58 – Commission notification of intent to construct wind farm	Requires anyone constructing a wind project over 5 MW to notify the Commission more than 4 months prior to construction.
	SB 60 – Energy Independence and Security Act of 2007 (EISA07)	Grants the PUC authority to implement the provisions of the Energy Independence and Security Act of 2007 (EISA07), which directed States to consider adopting certain standards like integrating energy efficiency into utility resource planning.
	SB 141 – Wind tower setbacks	Provides specific rules for how close a wind tower can be located to the adjacent property line. There are two categories of wind turbine - small and large.

	SB 184 – Wind easement open for utility use	Opens up wind easements for electric company use. It prevents wind developers from excluding power line easements from also running within their wind easement areas.
	HB 1112 – Transfer of wind easements	Clarifies that wind easements are not attached to the land and may be transferred independently of the land. This bill will require the easement holder to notify the landowner whenever an easement is traded or encumbered in some way.
	HB 1129 – CO_2 Pipelines	Grants the PUC authority over CO_2 pipelines.
	HB 1177 – Transmission line approvals	Redefines what constitutes a transmission line for purposes of the need for a PUC facilities permit. The bill changes the threshold such that a transmission line would be defined as being a line with a voltage greater than 115KV.

Minnesota

Year	Provision	Description
2008	SF 3337 (Omnibus Energy Bill) – RECB payments	Authorizes the PUC to approve automatic cost recovery for charges incurred by a utility for regional transmission projects built by another utility, but determined by MISO to benefit the first utility (RECB payments).
	SF 3337 (Omnibus Energy Bill) – Energy storage projects	Authorizes utilities to seek cost recovery for energy storage projects associated with power generation facilities that support the state's renewable energy requirements.
	SF 3337 (Omnibus Energy Bill) – Solar projects eligible for Conservation Improvement Program (CIP)	Allows utilities to use up to 5% of their CIP budget targeted for renewable energy projects, on solar electric (<100kw) or solar thermal projects. Authorizes that the Commissioner of Commerce can determine a different standard for cost effectiveness and may establish different utility performance standards.

	HF 3195 – Midwest Governors Greenhouse Gas Accord	Establishes the Legislative Greenhouse Gas Accord Advisory Group to advise the governor's MGGA stakeholder group and to participate in regional meetings and negotiations on the accord. Requires a cap and trade agreement entered into by the governor under the MGGA, to be approved by the legislature.
	HF 3195 – Greenhouse Gas Cap and Trade Program	Requires the Commissioners of Commerce and the Pollution Control Agency ("PCA") to provide a study to the legislature, by January 15, 2009, for the potential implementation of a cap and trade program for the state. Components of the study are to include: ➢ Evaluation of a regional program as it relates to existing or pending federal cap and trade legislation. ➢ Evaluation of economic, environmental and public health impacts. ➢ Potential cap and trade revenue and expenditure studies. ➢ Options for the state to supplement the MGGA, join another regional program, or implement its own program, if a model rule to support the state's emission reduction goals is not completed.

	SF 3337 (Omnibus Energy Bill) – Greenhouse Gas Emissions Reduction Attainment	Creates a process for the state to develop policies to attain its greenhouse gas reduction goals. By January 15 of each odd numbered year, requires the Commissioners of Commerce and the PCA to report to the legislature on the amount of greenhouse gas reductions achieved and the reductions necessary to meet the state's goals. Requires the commissioners of commerce and PCA to provide an annual legislative proposal on legislation necessary to achieve the state's goals. Legislation must be based on principles that support the attainment of the state's greenhouse reduction goals, incorporates energy conservation, provides public education, involves government, addresses economic dislocation concerns and is coordinated with other federal and regional greenhouse gas reduction requirements.
2009	SF 550 (Omnibus Energy Bill) – Incentives for Conservation	Authorizes the Commission to adopt a conservation incentive such that implementation of conservation is a preferred choice for the public utility considering the impact of conservation on earnings
	SF 550 (Omnibus Energy Bill) – Light Rail Central Corridor	Authorizes utility cost recovery for expenses associated with new, replaced or relocated facilities along the Light Rail Central Corridor between Minneapolis and St. Paul.

	SF 550 (Omnibus Energy Bill) – Energy storage projects	Expands cost recovery authorization from 2008 session to include energy storage devices that "advance research and understanding of how storage devices may improve renewable energy projects."
	SF 550 (Omnibus Energy Bill) – Xcel Energy wind energy requirement	Amends Xcel Energy's 25% wind energy requirement to allow 1% solar and 24% wind.
	SF 550 (Omnibus Energy Bill) – Solar projects	Increases the authorized use of conservation spending for solar projects, from 5% to 10%.
	SF 550 (Omnibus Energy Bill) – Standard contract for small renewable projects	Requires utilities to file a standardized contract for renewable energy projects under 5 MW.
	SF 550 (Omnibus Energy Bill) – County CBED projects	Authorizes counties to enter into joint agreements to purchase and develop CBED projects.

	SF 550 (Omnibus Energy Bill) – Transmission	Increases the appraisal fees for a utility's use of eminent domain for a high voltage transmission line, from $500 to $3000. Requires the Commissioner of Commerce to submit an annual report on transmission adequacy to the chairs of the legislative energy policy committees.
	SF 657 – Energy stimulus	Directs the use of $196 million in federal energy stimulus funding for renewable energy and energy efficiency purposes.

Michigan

Year	Provision	Description
2008	SB 213 – Renewable Portfolio Standard	Requires the state's investor-owned utilities, alternative retail suppliers, electric cooperatives and municipal electric utilities to generate 10% of their retail electricity sales from renewable energy resources by 2015. The standard allows utilities to use energy optimization and advanced cleaner energy systems to meet a limited portion of the requirement. Energy optimization is also subject to a separate requirement, but credits achieved under one standard may be exchanged for credits under the other standard subject to certain limitations.

Wisconsin

Year	Provision	Description
2008	SB 40 (State Executive Budget Bill) – Wisconsin Energy Independence Grant and Loan Program	Supports development of alternative energy and fuel sources by creating this new program.
	SB 40 (State Executive Budget Bill) – Public Intervenor	Restores authority for the state's Department of Justice to appoint an Office of the Public Intervenor within the Department to "enhance our natural resources by lobbying government agencies and legislators directly to ensure public rights are addressed as part of environmental protection legislation and policies by acting as a check and balance over state agencies."
	SB 40 (State Executive Budget Bill) – Act 141 Implementation	Reorganizes the Department of Administration's Division of Energy to better reflect its responsibilities following the implementation of 2005 Act 141 by transferring Focus on Energy to PSCW. Creates a new "Office of Energy Independence" to coordinate the state's efforts to grow Wisconsin's bio and renewable economies.
	SB 40 (State Executive Budget Bill) – Tax Exemption	Provides tax exemption on the sale of electricity used in manufacturing.

	SB 40 (State Executive Budget Bill) – Gross Receipts Tax	Eliminates a provision that would have increased the state's gross receipts tax on electricity sales from 1.59% to 3.19%, thus maintaining the tax rate at 1.59%.
	AB 625 – Renewable resource facilities & energy use & sale	Authorizes a school board to construct or acquire a renewable resource facility and to use the energy generated by the facility or sell it at wholesale.

APPENDIX B
Resource Plan Basics and Strategist Modeling

Xcel Energy provides electricity and natural gas to customers in the states of Minnesota, North Dakota, South Dakota, Wisconsin and Michigan through two operating companies, Northern States Power Company - Minnesota ("NSP-M") and Northern States Power Company – Wisconsin ("NSP-W").

Although NSP-M and NSP-W are separate operating companies, we have long planned and operated an integrated system to serve the needs of both companies. Aggregating the demand and energy requirements of the two operating companies creates a larger demand base, which can increase our access to available cost-effective resource options. The combined load of the two companies has allowed us to develop a diverse portfolio of resources that supplies our customers with energy generated using nuclear, coal, hydro, natural gas, wind, biomass and oil.

Xcel Energy's long-term resource planning process evaluates the future resource needs of the system in light of a number of factors, including projected customer energy needs, our current owned and purchased resources, future opportunities and costs for resource development and acquisition, and existing and potential state and federal legal and regulatory requirements. Every two to three years we perform a comprehensive analysis to develop a 15-year plan and a five-year action plan that describes our proposals to cost-effectively and reliably meet our customer needs in North Dakota, South Dakota, Minnesota, Wisconsin and Michigan.

Our Current Resource Plan

The 2007 resource plan we developed is the set of resources that we propose to add to the system over time to meet our projected needs for the time period 2008-2022. It identifies the amount, type, and timing of each resource addition. Our plan is developed through careful analysis of the costs of various resource options that are

available to meet our system and regulatory requirements. We use the Strategist resource planning software to assist in that analysis.

In that current Resource Plan, we included:

- upgrades at our Sherco, Monticello and Prairie Island plants;
- a partial extension of our purchase agreement with Manitoba Hydro;
- a proposed repowering of our coal units at Black Dog; and
- sufficient wind to meet all of our jurisdictional renewable requirements.

In addition, the plan identified several hundred MW of new natural gas projects that would be needed to meet customer needs over the next 15 years, and included an aggressive energy efficiency program that is designed save enough energy and capacity to meet 1.3% of annual retail sales in Minnesota in 2012.

We believe that our current Resource Plan provides a robust resource expansion plan that meets the needs of our customers as well as all of our statutory and regulatory requirements at a reasonable cost. Our Plan does not rely on any single technology or fuel and in fact will add at various times new energy and capacity fueled by wind, hydro, coal, gas and nuclear energy. The Plan performs well under every scenario analyzed and performs particularly well under scenarios where the cost of GHG regulation is at $20 or higher.

Strategist Resource Planning Model

Xcel Energy has used the Strategist model in our Resource Plans since 2000. Strategist is used to estimate the cost of resource expansion plans and to evaluate specific capacity alternatives. Strategist plays a central role in helping identify and refine resource options. The Strategist Model is also used to test the reasonableness and the robustness of this resource plan. We work to carefully and accurately characterize our current system and to develop assumptions that best reflect our expert opinion of likely future conditions. Strategist, in turn, helps with the analysis

of the myriad of options and "what if" scenarios that must be a part of a robust planning regime.

The model consists of four primary components.

- *Load Module* that contains Xcel Energy's load forecast, load management, and conservation programs. This module produces long-range estimates of the Company's net energy requirements and peak capacity requirement.
- *Generation Module* that contains the operating costs and performance characteristics for our thermal units, renewable resources, and transactions. This module uses an hourly dispatch simulation to estimate how demand will be met and what the associated costs and emissions will be.
- *Capital Project Module* that estimates the revenue requirement for capital projects such as new generating resources. This module keeps track of rate base, depreciation, taxes, and rate of return for existing and future capital projects.
- *Expansion Planning Module* that uses a dynamic programming algorithm to derive the least cost expansion plan. This module calculates the customer and societal costs for thousands of different resource combinations to arrive at the least cost plan.

For each expansion plan, Strategist calculates fuel consumption, fuel costs, O&M costs, emission rates, capital costs, and total revenue requirement. The total system costs are reported as the net present value of revenue requirements or "PVRR." This value is the sum of all operating, depreciation, return on rate base, and tax costs, less any revenues from sales discounted back to 2008 using the Company's most recently authorized weighted after tax cost of capital of 7.42%.

By using Strategist, we can demonstrate that our Plan will meet customer needs under a variety of conditions at a reasonable cost. Through Strategist, we test our Plan

under a number of possible futures and select a robust Plan that reflects our vision and meets all of our current and expected future legal and regulatory requirements.

Assumptions in the Current Resource Plan

Although the planning period in this report covers 2008-2022, Strategist analysis covers 2008-2047. The longer time interval can help to better estimate the costs and benefits of the long-lived resources proposed in this plan. The following is a list of important assumptions used in Strategist in developing our current Resource Plan.

Forecast

- We plan to meet the 50% probability level of forecasted peak demand and energy requirements.

Existing Fleet

- Cost and performance assumptions are consistent with historical data.
- Costs are escalated based on corporate estimates of expected inflation rates.
- Continued operation of our Sherco and King generating stations throughout the study period.
- Retirement of our Prairie Island nuclear generating station at the end of its proposed license renewal period (2034, 2035), and retirement of Monticello at the end of its current license (2030).
- Retirement of other facilities at their current expected end of life if within the resource planning period, unless we have specifically included costs of life extension.
- Continuation of our existing power purchase contracts until their contractual termination dates.
- Continued operation of Xcel Energy's hydroelectric resources based on historical performance.

Renewable Energy

- Addition of renewable energy resources capable of generating at least 12,198 GWh of eligible energy by 2020 in order to meet our requirement to generate at least 30% of our Minnesota retail electric sales from renewables by that date.
- Accreditation of wind resources in accordance with MAPP rules and based on historical performance (12.5% average)**,** and capacity factors based on hourly wind speed data from the 2006 Minnesota Wind Integration Study.
- Extension of the Federal Production Tax Credit through 2015.
- Additional ancillary service charges for wind based on the 2006 Minnesota Wind Integration Study.

Emissions

- Emission rates for existing and planned resources consistent with historical and expected performance.
- Cap and trade permit systems for SO_2, and NOx consistent with Title IV of the 1990 Clean Air Act Amendments[7].
- $17/ton charge for CO_2 starting in 2012 and escalating at 2.5% per annum with alternative scenarios showing a $4/ton value and a $30/ton scenario.
- Externality scenario analysis uses the Minnesota Public Utility Commission's updated high and low externality values.

Strategist uses generically defined resources to meet future demand when existing resources fall short. The Company used the following generic resources as model inputs for our current Resource Plan:

- 160 MW gas-fired Combustion Turbine peaking unit (CT)
- 600 MW gas-fired Combined Cycle intermediate unit (CC)
- 500 MW Super Critical Pulverized Coal base load unit with partial carbon sequestration (SCPCwSEQ)

[7] At the time of our September 2008 Resource Plan Reply Comments the Federal Clean Air Interstate Rule ("CAIR") and the Federal Clean Air Mercury Rule ("CAMR") had been resended by federal courts and therefore had been removed from our Strategist model.

- 100 MW Wind project (Wind)

The CTs become available for inclusion in the expansion plan starting in 2012, CCs in 2015, SCPC in 2015, and Wind in 2009. Cost and performance data for these units are based on a consultant's estimates and internal company data.

To determine how changes in our assumptions impact the costs or characteristics of different resource plans, we examine our plans under a number of scenarios. If a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. Instead, we may propose an expansion plan that is less sensitive to assumption changes, but slightly more costly in the baseline scenario. For this current Resource Plan, we tested the following scenarios.

- *Load.* The base forecast (unadjusted for DSM) has an average energy growth rate of 1.14%. The energy growth rate was adjusted down to average 1% and was also adjusted up to average 1.3%.
- *Fuel Cost.* The cost of natural gas, coal, and nuclear fuel were all independently adjusted up and down by 20%.
- *MISO.* Due to the unpredictability of future market conditions, Xcel Energy models itself as a stand-alone system without additional purchases and sales from the MISO day two market. In our sensitivity analysis, Strategist's Network Economy Interchange ("NEI") submodule was activated to simulate how the system might interact with the rest of MISO. However, this sensitivity requires highly speculative assumptions about supply and demand conditions in the rest of the market. The Company recommends that these results should be viewed as an estimate of one possible outcome, but not a precise prediction of what will occur in the future.

- *Capital Cost Escalation.* The base assumption in Strategist is that the cost of capital projects will increase at 1.99%. Cost escalation scenarios at 3% and 5% were also run to evaluate expansion plan sensitivity to escalation assumptions.

Modeling Wind Resources in Strategist

The Strategist Model creates an optimized (or least cost) expansion plan by evaluating different combinations of resources and selecting the combination that meets all of the model requirements at the lowest PVRR. We populate the model with a limited number of generic options representing various generating types such as a Combustion Turbine, a Combined Cycle and a Coal-fired Plant and a Wind facility.

However it has been the Company's experience that Strategist's has limited capability to "optimize" the amount of wind to add to an expansion plan. When Strategist optimizes an expansion plan, the model evaluates thousands of different combinations of wind and thermal resources to identify the portfolio of new resource additions that results in the lowest present value of revenue requirements.

When we have attempted to let Strategist optimize new wind additions we regularly confront two problems: 1) Extended model run times and 2)"All or Nothing" results.

Extended model run times refers to the time it takes for Strategist to finish an expansion plan optimization. Typically a Strategist run will finish in one to two hours. When we attempt to have Strategist optimize wind additions the run times jump to one to two days. The cause is wind's low capacity accreditation percent. We model 100 MW wind farms as generic alternatives. But in accordance with MISO rules these

wind farms are only accredited for approximately 12 MW towards our reserve margin requirements. When Strategist builds expansion portfolios there are relatively few combinations of 160 MW CTs, 600 MW CCs, and 500 MW Coal units that are realistically feasible to meet future reserve requirements. But the number of feasible combinations increases exponentially when a 12 MW (accredited) wind farm is added for consideration.

"All or Nothing" results are caused by wind being on the border of cost effectiveness. For example if we assume wind to cost $2,400/kW with a 39% capacity factor Strategist may produce an optimal expansion plan with several thousand MW of wind. But if we change our assumption to $2,500 and 37% capacity factor Strategist may include no wind at all in the expansion plan. A more reasoned approach to portfolio building would recognize that wind can be cost effective under a number of scenarios and should be included in an expansion plan at some level for the purpose of portfolio diversification and fuel cost / CO2 cost hedging. However, a reasoned portfolio shouldn't contain wind at a level that threatens system reliability, exceeds plausible transmission availability, or would exclusively rely on wind to meet growing demand.

We can approximate the optimal amount of wind in an expansion plan by testing the plan using many different levels of wind. If for example an expansion plan with 200 MW of wind has a lower PVRR than one with 100 MW of wind, it suggests that adding wind to the portfolio reduces the cost. To further explore this issue, we can continue to add increments of wind to the portfolio to see if PVRRs continue to go down. When we reach a point where the PVRRs increase with the incremental addition of wind, we have approximated the optimal wind level for that portfolio.

We currently develop our wind expansion plan based on renewable requirements in each jurisdiction and hard codes the plan into the model. We do not make additional wind available for the model to select, but we do test sensitivity levels around the amount of wind in the plan to determine the impact on PVRR. This is a reasonable method to determine an appropriate cost-effective level of wind in the portfolio, but it does not provide us with an optimized view of wind in the expansion plan. We are continuously working on new strategies both within and external to the Strategist model to evaluate the best level of wind in our expansion plan.

Table 1: Current Resource Plan Expansion Plan

Current Resource Plan Expansion Plan

	Planned Additions	Combined Cycle	Combustion Turbine	Wind	DSM
2009	RAHR 12MW	Riverside CC 511MW		250MW*	49MW
2010				260MW	109MW
2011	Monticello 68MW			400MW	118MW
2012	Sherco 3 12MW		160MW	250MW	118MW
2013	Prairie Island 82MW			100MW	133MW
2014			160MW	100MW	130MW
2015	Manitoba Hydro 375MW + 350MW Diversity Prairie Island 82MW	Black Dog Repowering 750MW		100MW	128MW
2016				100MW	140MW
2017				100MW	145MW
2018		600MW		100MW	148MW
2019				200MW	154MW
2020				200MW	169MW
2021	Manitoba Hydro 125 MW			100MW	169MW
2022				100MW	128MW

* Grand Meadow in-service Jan 09

Table 2: North Dakota Low DSM Scenario Expansion Plan

North Dakota Low DSM Scenario

	Planned Additions	Combined Cycle	Combustion Turbine	Coal	Wind	DSM
2009	RAHR 12MW	Riverside CC 511MW			100MW*	
2010						
2011	Monticello 68MW				200MW	
2012	Sherco 3 12MW		800MW		150MW	
2013	Prairie Island 82MW		320MW			
2014			320MW		50MW	
2015	Manitoba Hydro 375MW + 350MW Diversity Prairie Island 82MW	Black Dog Repowering 750MW				
2016		600MW				
2017						
2018				500MW		
2019						
2020				500MW		
2021	Manitoba Hydro 125 MW					
2022		600MW				

* Grand Meadow in-service Jan 09

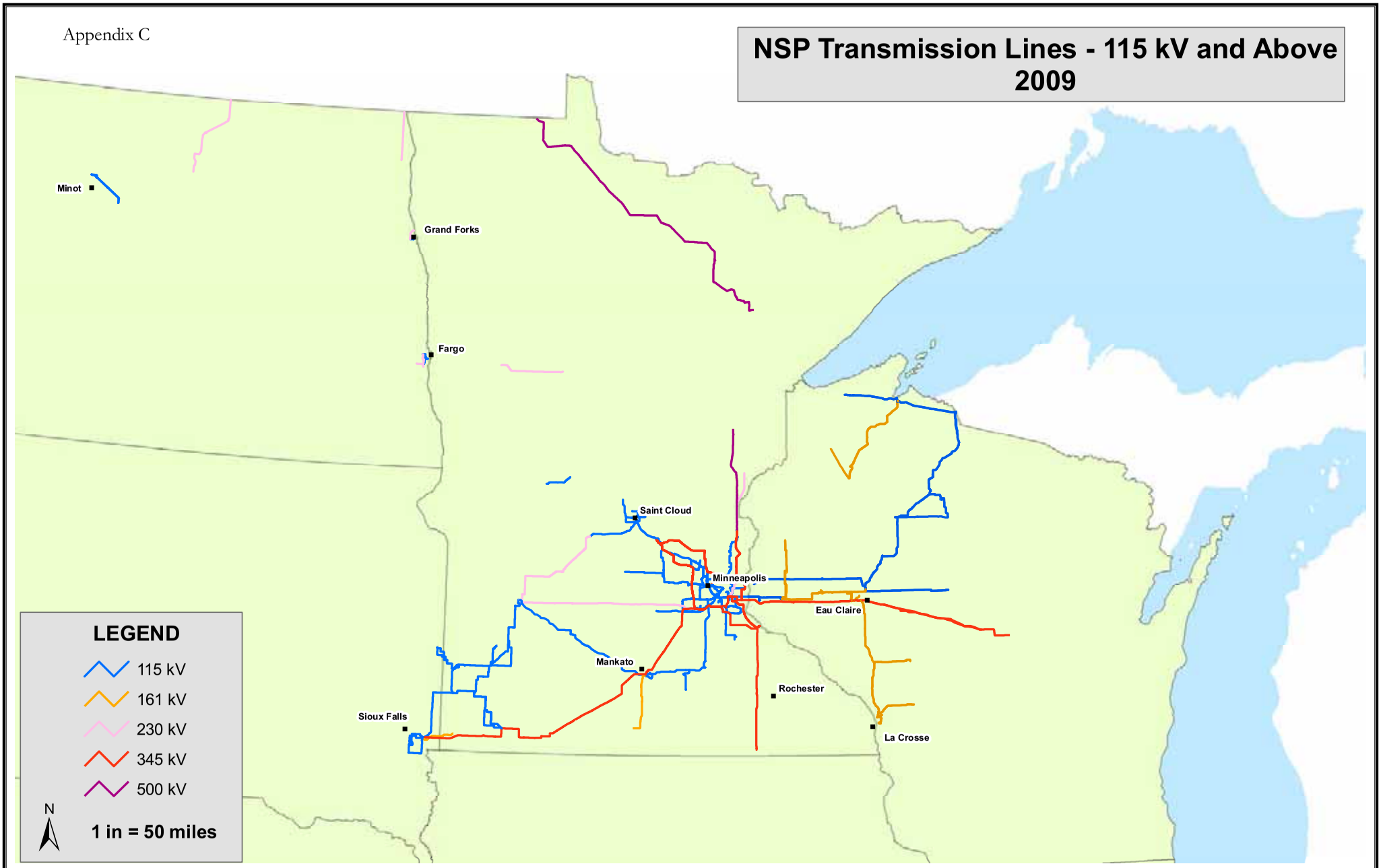
Table 3: North Dakota High DSM Scenario Expansion Plan

North Dakota High DSM Scenario

	Planned Additions	Combined Cycle	Combustion Turbine	Coal	Wind	DSM
2009	RAHR 12MW	Riverside CC 511MW			100MW*	49MW
2010						109MW
2011	Monticello 68MW				200MW	118MW
2012	Sherco 3 12MW		320MW		150MW	118MW
2013	Prairie Island 82MW					133MW
2014			160MW		50MW	130MW
2015	Manitoba Hydro 375MW + 350MW Diversity Prairie Island 82MW	Black Dog Repowering 750MW				128MW
2016						140MW
2017						145MW
2018			160MW			148MW
2019			160MW			154MW
2020						169MW
2021	Manitoba Hydro 125 MW					169MW
2022		600MW				128MW

* Grand Meadow in-service Jan 09

Appendix C


NSP Transmission Lines - 115 kV and Above
2009
Minot
Grand Forks
Fargo
Saint Cloud
Minneapolis
Eau Claire
Mankato
Rochester
Sioux Falls
La Crosse
LEGEND
115 kV
161 kV
230 kV
345 kV
500 kV
N
1 in = 50 miles