414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

March 15, 2011

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

Re: PETITION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE BLACK DOG GENERATING PLANT REPOWERING PROJECT
DOCKET NO. E002/CN-11-184

Dear Dr. Haar:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") is pleased to submit to the Minnesota Public Utilities Commission ("Commission") for consideration this Application for a Certificate of Need for the Black Dog Generating Plant Repowering Project. Commission approval will allow us to increase the electrical generating capabilities of the Minnesota plant by approximately 450 MW (from a current capacity of about 250 MW to about 700 MW). The Certificate of Need application is submitted pursuant to Minn. Stat. § 216B.243 and Minn. R. 7849 and demonstrates that the project is cost-effective, provides significant environmental benefits, and adds to our ability to quickly respond to intermediate and peaking needs.

Increased capacity will be achieved through the repowering of the existing coal fired units to a larger natural gas fired combined cycle facility. On August 2, 2010 we filed our 2010 Resource Plan (Docket No. E002/RP-10-825), which indicated that even after including the demand-side management and renewable requirements of 2007 legislation, we are projecting a deficit starting in 2014. Additionally we stated a need for intermediate and peaking facilities to follow our wind generation resources. We also indicated that we would study the need for repowering our Black Dog facilities. This CON is as a result of that study. We submit this application as one element of our resource plan. Approval of this application will not only provide needed resources, it will also add environmental benefits and provide a valuable variable resource with load following capabilities.

The Company intends to file the accompanying Site and Route Permit Application in early-May.

Minn. R. 7849.0210, subp. 1 establishes an application and processing fee of $10,000 plus $50 for each megawatt of plant capacity, plus such additional fees as are reasonably necessary for completion of the evaluation of need for the proposed facility. The proposal will increase the generating capacity at the Plant site by 450 MW, resulting in an estimated total fee of $32,600. A check in that amount accompanies our application.

Information in Appendix H of this filing has been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). A separate trade secret version of Appendix H will be filed electronically and mailed to those parties that are eligible and request paper service. In particular, the cost information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Disclosure of the trade secret provisions would have a detrimental effect by providing valuable information not otherwise readily ascertainable and from which could be obtained economic value.

We are serving the Office of the Attorney General and the Office of Energy Security. A filing summary will be served on parties on the attached miscellaneous service list and to those parties to the Company's last general rate case. Copies of our Application can be obtained from the Xcel Energy web site at www.xcelenergy.com.

Please contact Sara Cardwell at sara.j.cardwell@xcelenergy.com or (612) 330-7975 if you have any questions regarding this filing.

Sincerely,

/S/

Scott M. Wilensky
Vice President
Regulatory Affairs

Enclosures

c: Service Lists

Xcel Energy

Xcel Energy Services Inc.
d/b/a Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
303-628-2644

Wells Fargo Bank, N.A.
115 Hospital Drive
Van Wert, OH 45891

0000180232

56-382/412

Date 03/03/11

9600012696

$32600.00 USD

Pay THIRTY TWO THOUSAND SIX HUNDRED & 00/100********** DOLLARS

VOID IF NOT CASHED IN 90 DAYS

To The Order Of

MINNESOTA PUBLIC UTILITIES COMMISSION
121 7TH PL E STE 350
ST PAUL MN 55101

THE FACE OF THIS DOCUMENT HAS A COLORED BACKGROUND ON WHITE PAPER AND A TRUE WATERMARK HOLD TO LIGHT TO VIEW

E002/CN-11-184

OK FOR PAPER COPY
TRANSMITTAL

Burl Haar 3/17/11

Burl Haar, Executive Secretary/Date

Xcel Energy®

RECEIVED
MAR 17 2011
MINNESOTA PUBLIC UTILITIES COMMISSION

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

March 15, 2011

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

- VIA ELECTRONIC FILING -

Re: PETITION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE BLACK DOG GENERATING PLANT REPOWERING PROJECT
DOCKET NO. E002/CN-11-184

Dear Dr. Haar:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") is pleased to submit to the Minnesota Public Utilities Commission ("Commission") for consideration this Application for a Certificate of Need for the Black Dog Generating Plant Repowering Project. Commission approval will allow us to increase the electrical generating capabilities of the Minnesota plant by approximately 450 MW (from a current capacity of about 250 MW to about 700 MW). The Certificate of Need application is submitted pursuant to Minn. Stat. § 216B.243 and Minn. R. 7849 and demonstrates that the project is cost-effective, provides significant environmental benefits, and adds to our ability to quickly respond to intermediate and peaking needs.

Increased capacity will be achieved through the repowering of the existing coal fired units to a larger natural gas fired combined cycle facility. On August 2, 2010 we filed our 2010 Resource Plan (Docket No. E002/RP-10-825), which indicated that even after including the demand-side management and renewable requirements of 2007 legislation, we are projecting a deficit starting in 2014. Additionally we stated a need for intermediate and peaking facilities to follow our wind generation resources. We also indicated that we would study the need for repowering our Black Dog facilities. This CON is as a result of that study. We submit this application as one element of our resource plan. Approval of this application will not only provide needed resources, it will also add environmental benefits and provide a valuable variable resource with load following capabilities.

The Company intends to file the accompanying Site and Route Permit Application in early-May.

Minn. R. 7849.0210, subp. 1 establishes an application and processing fee of $10,000 plus $50 for each megawatt of plant capacity, plus such additional fees as are reasonably necessary for completion of the evaluation of need for the proposed facility. The proposal will increase the generating capacity at the Plant site by 450 MW, resulting in an estimated total fee of $32,600. A check in that amount accompanies our application.

Information in Appendix H of this filing has been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). A separate trade secret version of Appendix H will be filed electronically and mailed to those parties that are eligible and request paper service. In particular, the cost information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Disclosure of the trade secret provisions would have a detrimental effect by providing valuable information not otherwise readily ascertainable and from which could be obtained economic value.

We are serving the Office of the Attorney General and the Office of Energy Security. A filing summary will be served on parties on the attached miscellaneous service list and to those parties to the Company's last general rate case. Copies of our Application can be obtained from the Xcel Energy web site at www.xcelenergy.com.

Please contact Sara Cardwell at sara.j.cardwell@xcelenergy.com or (612) 330-7975 if you have any questions regarding this filing.

Sincerely,

/S/

Scott M. Wilensky
Vice President
Regulatory Affairs

Enclosures

c: Service Lists

APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE BLACK DOG REPOWERING PROJECT

PUC Docket No. E-002/CN-11-184

March 15, 2011

Submitted by
Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR A CERTIFICATE OF NEED FOR THE BLACK DOG GENERATING PLANT REPOWERING PROJECT	DOCKET NO. E002/CN-11-184 **Petition**

SUMMARY OF FILING

Please take notice that on March 15, 2011, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or "the Company"), filed with the Minnesota Public Utilities Commission ("Commission") an application for a Certificate of Need ("CON") for the Black Dog Generating Plant ("Plant") Repowering Project ("Project") and the associated transmission necessary for the direct interconnection of the Project.

The Project consists of replacing the coal-fired generating Units 3 and 4 at the Black Dog Plant site with about 700 MW of gas fired, combined cycle, generation located in what is now the coal storage yard at the Plant. The total output of Black Dog Units 3 and 4 was summer rated at 253 MW in 2010. As part of the Project, these units will operate solely on natural gas starting in 2013 and be shut down in 2016 after the new combined cycle facility is placed in service.

This filing also initiates the Alternative Competitive Resource Acquisition process established in Docket No. E002/RP-04-1752. Prospective alternative providers must intervene in support of their own proposal in a contested case proceeding.

Application to the Minnesota Public Utilities Commission
for a Certificate of Need
Black Dog Repowering Project

Table of Contents

1 Summary 1-1

1.1 Introduction 1-1

1.2 Regulatory Framework 1-5

1.2.1 Certificate of Need 1-5

1.2.2 Siting and Environmental Review 1-5

1.2.3 Environmental Permits 1-6

1.3 Demand and Supply Need 1-6

1.3.1 Demand 1-7

1.3.2 Supply 1-8

1.4 Analysis of Alternatives 1-9

1.5 Project Description 1-11

1.5.1 Fuel 1-11

1.5.2 Construction Schedule 1-11

1.5.3 Operation 1-12

1.5.4 Cost 1-12

1.6 Environmental Performance 1-13

1.6.1 Air 1-13

1.6.2 Water 1-13

1.6.3 Noise 1-14

1.6.4 Land Use 1-14

1.7 Certificate of Need Criteria 1-14

2 General Information and Regulatory Permits 2-1
2.1 Applicant Information 2-1
2.2 Description of Business and Service Area 2-1
2.3 Certificate of Need Process and Competitive Acquisition 2-2
2.4 Notices, Procedural Guidance and Schedule 2-4
2.5 Related Filings and Permits 2-5
2.5.1 Site and Route Permits 2-6
2.5.2 Gas Pipeline Routing Permit 2-6
2.5.3 Transmission System Filings 2-6
2.5.4 Environmental Permits 2-7
2.5.5 Other Permits, Approvals or Notifications 2-8
3 Demand and Supply Need 3-1
3.1 Demand and Energy Forecasts 3-1
3.1.1 Forecasts Incorporate DSM 3-4
3.1.2 Reserve Requirements 3-5
3.2 Generation Requirements 3-6
3.3 Supply: Black Dog Units 3 and 4 3-8
3.3.1 Ozone NAAQS 3-9
3.3.2 CAIR Caps/Proposed CAIR Replacement Rule 3-10
3.3.3 Proposed Rule for CCBs Management 3-10
3.3.4 CO_2 Regulation 3-10
3.3.5 Hazardous Air Pollutants MACT Rule 3-11
3.3.6 SO_2/NO_2 Primary NAAQS 3-11
3.3.7 SO_2/NO_2 Secondary NAAQS 3-12
3.3.8 Clean Water Act 316(b) Cooling Water Intake Rule 3-12

3.3.9 Effluent Guidelines 3-12
3.3.10 Summary of Potential Emissions Control Rule Changes 3-13
3.4 Conclusion: Resource Needs 3-13
3.5 Consequences of Project Delay 3-14
4 An Examination of Alternatives: Project is Most Reasonable and Prudent Alternative 4-1
4.1 Alternative Evaluation Criteria and Project Objectives 4-1
4.2 Alternatives Evaluation Approach 4-3
4.3 Qualitative Screening of Alternatives 4-3
4.3.1 Increased Efficiency of Existing Facilities 4-3
4.3.2 Long-Term Purchased Power 4-4
4.3.3 Short-Term Purchased Power 4-5
4.3.4 New Transmission Lines 4-6
4.3.5 New Generating Facilities of a Different Size or Type 4-6
4.3.6 Demand-Side Management 4-7
4.3.7 Distributed Generation 4-7
4.3.8 Renewable Energy Alternatives 4-8
4.3.9 No Facility 4-10
4.4 Economic and Environmental Analysis 4-10
4.4.1 Strategist Modeling Tool 4-11
4.4.2 Base Case Assumptions and Load Forecasts 4-12
4.4.3 Black Dog Generating Plant Life Extension 4-12
4.4.4 Black Dog Repowering Project 4-13
4.4.5 Alternative Generation Option 4-14
4.4.6 Biomass Alternative 4-14

4.4.7 Modeling Results 4-14
4.4.8 Cooling Tower Sensitivity 4-17
4.4.9 Delay Scenario 4-18
4.4.10 Emissions 4-19
4.5 Alternatives Evaluation: Project is the Best Option 4-20
4.5.1 Best for Service Need 4-21
4.5.2 Best for System Reliability 4-21
4.5.3 Best for Environment 4-21
4.5.4 Most Cost Effective 4-22
4.6 Rate Impact 4-22
5 Project Description 5-1
5.1 Existing Plant Information 5-1
5.2 Description of Proposed Fuel and Operating Cycle 5-3
5.3 Location and Land Use 5-6
5.4 Structures and Structure Height 5-10
5.5 Project Output 5-10
5.6 Project Sizing 5-10
5.7 Fuel Use 5-11
5.8 Transmission 5-11
5.9 Natural Gas Pipeline 5-12
5.10 Construction 5-13
5.10.1 Generation Block 5-13
5.10.2 Transmission 5-13
5.11 Project Operation 5-14
5.11.1 Project Dispatch 5-14

5.11.2 Load Following 5-15
5.11.3 Capacity Factor 5-15
5.12 Project Operational Data 5-15
5.13 Maintenance Requirements 5-17
5.13.1 Generation 5-17
5.13.2 Transmission 5-18
5.14 Project Cost Evaluation 5-19
6 Environmental Information 6-1
6.1 Air Impacts 6-1
6.1.1 Air Emissions 6-1
6.1.2 Transmission Air Emissions 6-4
6.1.3 Fugitive Dust 6-5
6.2 Noise Impacts 6-6
6.3 Water Needs 6-7
6.4 Waste Generation 6-8
6.5 Electric and Magnetic Fields 6-10
6.5.1 Electric Fields 6-11
6.5.2 Magnetic Fields 6-11
6.6 Stray Voltage 6-17
6.7 Vehicle Use and Metal Buildings Near Power Lines 6-17
6.8 Radio and Television Interference 6-17
6.9 Land Requirements 6-18
6.10 Vegetation and Wildlife 6-19
6.10.1 Wildlife 6-20
6.10.2 Vegetation Cover 6-21

6.10.3 Threatened and Endangered Species 6-21
6.11 Human Settlement 6-22
6.12 Archeological and Historic Resources 6-24
6.13 Traffic and Transportation Infrastructure 6-26
6.14 Work Force Requirements 6-26
7 Project Benefits Society 7-1
7.1 Society Benefits from Reliable and Low Cost Electricity Sources 7-1
7.2 Provides Value to Customers 7-2
7.3 Efficiently Uses Existing Plant Site 7-2
7.4 Best Fit to Existing Transmission Facilities 7-3
7.5 Results in Lower Emissions 7-3
7.6 Creates Jobs 7-3
7.7 Supports Future Economic Development 7-3
7.8 Provides Tax Benefits 7-4
8 Project Complies with Rules and Policies 8-1
8.1 Project is Consistent with Minnesota Energy Policy 8-1
8.1.1 Legislative Preference 8-1
8.1.2 State Energy Policy 8-3
8.1.3 Non-Proliferation Policy 8-3
8.2 The Project Complies with Federal and State Environmental Regulations 8-4
8.3 Carbon Risk Analysis Compliance 8-4

List of Tables

Table 2-1 Publications List

Table 3-1 DSM Goals Approved in 2010-12 CIP Triennial Plan

Table 4-1 Cost Comparison of Repowering Project to Alternatives

Table 4-2 Cost Sensitivity Analysis

Table 4-3 Cooling Tower Sensitivity: PVRR Comparison of Project to Alternatives

Table 4-4 Emissions Differences between the Repowering Project and the Alternatives (Tons Emitted 2010-2049)

Table 4-5 Percent Increase in Rates for the Black Dog Repowering Project and Alternatives

Table 5-1 Existing Black Dog Generating Plant Units 3 and 4 Operational Information

Table 5-2 Structure Design Summary

Table 5-3 Project Operational Information

Table 6-1 Estimated Project Air Emissions

Table 6-2 Estimated Maximum Contributions to Ambient Air Quality

Table 6-3 Applicable Ambient Air Quality Standards for Transmission Projects

Table 6-4 Liquid and Solid Wastes

Table 6-5 Calculated Electric Fields (kV/m) for Proposed Transmission Line Designs (One meter above ground)

Table 6-6 Calculated Magnetic Flux density (milligauss) for Proposed 345 kV Transmission Line Designs (One meter above ground)

Table 6-7 Population and Economic Characteristics

Table 6-8 Previously Identified Historic Properties Near the Plant Site

List of Figures

Figure 1-1 Project Location
Figure 1-2 Forecasted Resource Needs by Year
Figure 2-1 Xcel Energy Upper Midwest Service Territiory
Figure 3-1 Median Base Summer Peak Demand (MW)
Figure 3-2 Median Net Energy (MWh)
Figure 3-3 Median Base Summer Peak Forecast
Figure 3-4 Medium Net Summer Peak Demand
Figure 3-5 Requirements and Resources 2011-2024
Figure 3-6 Forecasted Resource Needs by Year
Figure 4-1 Fuel Use with Black Dog Repowering
Figure 4-2 Fuel Use with Black Dog Life Extension
Figure 5-1 Coal Fired Plant Schematic Diagram
Figure 5-2 Schematic Diagram of a 2 on 1 Combined Cycle Facility
Figure 5-3 Project Layout
Figure 5-4 Double Circuit Transmission Line Structure
Figure 5-5 Preliminary Rendering Diagram

Appendices

Appendix A Xcel Energy System Demand and Capability Data
Appendix B Strategist Assumptions
Appendix C Xcel Energy Demand Side Management Programs
Appendix D Guidance for Prospective Competitors
Appendix E Conductor Specifications
Appendix F MN DNR NHIS Review
Appendix G Minnesota SHPO Letter
Appendix H Trade Secret Project Specific Information

APPLICATION FOR CERTIFICATE OF NEED
Content Requirement and Completeness Checklist

Authority	Required Information	Location of Required Content
7849.0120A	Showing that denial would adversely affect adequacy, reliability and efficiency	Chapter 3
1	Demand forecast for type of energy supplied by proposed facility is accurate	Appendix A
2	Effects of applicant's conservation program and state and federal conservation programs	§ 3.1.1, § 4.3.6
3	Effects of applicant's promotional practices on energy demand	§ 3.1.1, § 4.3.6
4	Ability of current facilities and facilities not requiring certificate of need to meet future demand	Chapter 4
5	Effect of proposed facility in making efficient use of resources	Chapter 4, § 7.3
7849.0120B	A more reasonable and prudent alternative has not been demonstrated	Chapter 4
1	Appropriate size, type and timing compared to reasonable alternatives	Chapter 4
2	Cost of facility and of its energy compared to reasonable alternatives	§ 4.4, § 4.5
3	Effects on natural and socioeconomic environment vs. reasonable alternatives	Chapter 4, Chapter 6, Chapter 7
4	Expected reliability of facility compared to reasonable alternatives	Chapter 4, Appendix B

Authority	Required Information	Location of Required Content
7849.0120C	Project benefit society by protecting the natural and socioeconomic environment, including human health, considering:	Chapter 6, Chapter 7
1	Relationship of facility to overall state energy needs	Chapter 7, Chapter 8
2	Effects of facility on natural and socioeconomic environment compared to not building facility	Chapter 7
3	Effects of facility inducing future development	§ 7.7
4	Socially beneficial uses of the output of the facility, including to protect or enhance environmental quality	§ 7.5
7849.0120D	Project will comply with relevant policies and regulations of other state and federal agencies and local governments	Chapter 8
7849.0200	Application procedures and timing	Cover Letter
7849.0210	Filing fee to accompany application	Cover Letter
7849.0220	Contents of application	Table of Contents; Content Requirements Checklist
7849.0230	Draft environmental report	Not applicable to LEGF; Prepared by OES using information provided
7849.0240	Need Summary and Additional Considerations	Chapter 1
7849.0240, Subp. 1	Need summary contains major factors that justify need for facility	Chapter 1

Authority	Required Information	Location of Required Content
7849.0240, Subp. 2A	Additional considerations address socially beneficial uses of facility output, including uses to protect or enhance environmental quality	Chapter 4, Chapter 6, Chapter 8
7849.0240, Subp. 2B	Promotional activities that may have given rise to demand	§ 3.1.1, § 4.3.6
7849.0240 Subp. 2C	Effects of the facility in inducing future development	§ 7.6, § 7.7
7849.0250	Description of proposed LEGF and alternatives	Chapter 4, Chapter 5
A	Description of the facility, including:	Chapter 5
1	Nominal generating capability and economies of scale on the facility size and timing	§ 4.4, §5.5, §5.6, Table 5-3,
2	Anticipated operating cycle including expected annual capacity factor	§ 5.11, Table 5-3
3	Type of fuel used, including reason for choice of fuel, availability of fuel and alternative fuels, if any	Chapter 4, § 5.7
4	Anticipated heat rate of the facility	Appendix H
5	Anticipated areas where the proposed facility could be located	§ 5.3
B	Discuss alternatives available	Chapter 4
1	Purchased power	§ 4.3.2, § 4.3.3
2	Increased efficiency of existing facilities, including transmission lines	§ 4.3.1, § 4.3.4
3	New transmission lines	§ 4.3.4

Authority	Required Information	Location of Required Content
4	New generating facilities of a different size or using a different energy source as fuel	§ 4.3.5, § 4.3.7, § 4.3.8, § 4.4
5	Any reasonable combinations of the alternatives listed in items 1-4	§ 4.2, § 4.3, § 4.4
C	For the facility and for each alternative in B that could provide electric power at the asserted level of need, discuss:	§ 4.4
1	Capacity cost in current $/kW	Appendices B & H
2	Service life	Appendix B, Table 5-3
3	Estimated average annual availability	§ 5.11, § 5.12, § 5.13, Table 5-3, Appendix B
4	Fuel costs in current $/kWh	Appendices B & H
5	Variable operating and maintenance costs in current $/kWh	Appendices B & H
6	Total cost in current $/kWh	Appendices B & H
7	Estimated rate impact, system wide and in Minnesota, assuming a test year beginning with the proposed in-service date	§ 4.6, Table 4-5
8	Efficiency, expressed for a generating facility as the estimated heat rate, or for a transmission facility as estimated losses under maximum and average loading conditions	Appendices B & H
9	Major assumptions in providing the information in items 1-8, including projected escalation rates for fuel costs, O&M costs, and capacity factors	Appendices B & H

Authority	Required Information	Location of Required Content
D	Map showing the applicant's system	Figure 2-1
E	Such other relevant information about the proposed facility and each alternative as may be relevant to need determination	Chapter 4, Appendix B
7849.0270-0290	System load, annual consumption forecast, capacity and conservation program information	Chapter 3, Appendix A
7849.0270	Peak Demand and Annual Consumption Forecast	Appendix A
7849.0270 subpt. 1	Pertinent data concerning peak demand and annual electrical consumption	Appendix A
7849.0270 subpt. 2	Provide the following data for each forecast year:	–
A	Annual consumption by consumers within the MN service area	§ 3.1, Appendix A
B	Estimates of number of consumers and their annual electrical consumption for:	Appendix A
1	Farm, excluding irrigation and drainage pumping	Appendix A
2	Irrigation and drainage pumping	Appendix A
3	Nonfarm Residential	Appendix A
4	Commercial	Appendix A
5	Mining	Appendix A
6	Industrial	Appendix A
7	Street and highway	Appendix A
8	Electrified transportation	Appendix A

Authority	Required Information	Location of Required Content
9	Other	Appendix A
10	The sum of subitems (1) to (9)	Appendix A
C	Estimated power demand at annual peak demand, broken down as in B.	Appendix A
D	System peak demand by month	Appendix A
E	Estimated annual revenue requirement per kW-hr (in current dollars)	Appendix H
F	Estimated average system weekday load factor by month	Appendix A
7849.0270 subpt. 3	Detail of the forecast methodology employed in subpt. 2, including:	Appendix A
A	Overall methodological framework used	Appendix A
B	Specific analytical techniques used, their purpose and where used	Appendix A
C	Manner in which the specific techniques are related	Appendix A
D	Where statistical techniques have been used:	Appendix A
E	Forecast confidence levels or ranges for peak demand and consumption	Appendix A
F	A brief analysis of the methodology used, including:	Appendix A
1	Its strengths and weaknesses	Appendix A
2	Its suitability to the system	Appendix A
3	Cost considerations	Appendix A
4	Data requirements	Appendix A

Authority	Required Information	Location of Required Content
5	Past accuracy	Appendix A
6	Other factors considered significant by the applicant	Appendix A
G	Explanation of discrepancies between current and previous forecasts	Appendix A
7849.0270 subpt. 4	Discussion of the database used in current forecasting, including:	Appendix A
A	Complete list and description of all datasets used in the forecast	Appendix A
B	Clear identification of adjustments made to raw data including:	Appendix A
1	The nature of the adjustment	Appendix A
2	The reason for the adjustment	Appendix A
3	The magnitude of the adjustment	Appendix A
7849.0270 subpt. 5	Discussion of each assumption made in forecast preparation, including:	Application and Appendix A
A	Availability of alternate sources of energy	Chapter 4
B	Expected conversion from other fuels to electricity or vice versa	Chapter 4
C	Future prices and their projected impact upon system demand	Appendix A
D	Subpt. 2 data that is not available historically or internally generated	Appendix A
E	Impact of energy conservation programs upon electrical demand	Appendix C
F	Any other factor considered in preparing	Chapter 3, Appendix A

Authority	Required Information	Location of Required Content
	the forecast	
7849.0270 subpt. 6	Applicant shall provide:	Appendix A
A	Description of coordination of load forecasts with other systems	Appendix A
B	Description of the manner in which forecasts are coordinated	Appendix A
7849.0280	Description of ability of existing system to meet forecast demand	Chapter 3, Chapter 4
A	Discussion of power planning programs applied	Chapter 3, Appendix B
B	Seasonal firm purchases and sales for each utility in each forecast year	Appendix B
C	Seasonal participation purchases and sales for each utility in each forecast year	Appendix B
D	For the summer and winter season of each forecast year:	Appendix B
E	Load generation capacity for purchases, sales, and generation in years subsequent to application (see D 1-13)	Appendix B
F	Load generation capacity for projected purchases, sales and generation in years subsequent to application (see D 1-13)	Appendix B
G	List of proposed additions and retirements in generating capacity for each forecast year subsequent to application	Appendix B
H	Graph of monthly adjusted net demand and capability; plot of difference between capability and maintenance outages	Appendix B

Authority	Required Information	Location of Required Content
I	Appropriateness and method of determining system reserve margins	Appendix B
7849.0290	Application must include the following regarding conservation programs:	–
A	Party (ies) responsible for energy conservation and efficiency programs	Appendix C
B	List of energy conservation and efficiency goals and objectives	Appendix C
C	Description of programs considered, implemented and rejected	Appendix C
D	Description of major accomplishments in conservation and efficiency	Appendix C
E	Description of future plans with respect to conservation and efficiency	Appendix C
F	Quantification of the manner by which these programs impact the forecast	Appendix C
7849.0300	Consequences of indefinite delay or 1,2, or 3 year postponement	§ 3.5, § 4.4.9
7849.0310	Environmental information requested	Chapter 6, Table 6-1, Table 6-2
7849.0320	Provide data for each alternative that would involve LEGF construction	Chapter 4, Appendix B
7849.0320A	Estimated range of land requirements for the facility and a discussion of assumptions on land requirements, water storage, cooling systems, solid waste storage	§ 6.9, Table 6-4, Appendix B
B	Estimated vehicular, rail, barge traffic generated by construction and operation	§ 5.3, § 5.10, § 6.13

Authority	Required Information	Location of Required Content
	of the facility	
C	For fossil-fueled facilities:	–
1	Expected regional fuel sources for the facility	§ 1.5.1, § 5.9, Appendix B
2	Typical fuel requirement during operation at rated capacity and annual fuel requirement at expected capacity factor	Appendices B and H
3	Expected rate of heat input in Btu per hour at rated capacity	Appendices B and H
4	Typical range of heat value of the fuel (in Btu/lb, Btu/gallon or Btu/1000Cf) and typical average heat value	Appendices B and H
5	Typical ranges of sulfur, ash and moisture content of the fuel	Appendices B and H
D	For Fossil fueled facilities:	–
1	Estimated range of trace element emissions and maximum emissions of SO_2, NO_x, and PM in lbs/hour during operation at rated capacity	Table 6-1, Table 6-2
2	Estimated range of maximum contributions to 24-hour average ground level concentrations at specified distances from stack of SO_2, NO_x and PM in micrograms/cubic meter at rated capacity and assuming generalized worst-case meteorological conditions	Table 6-2, § 6.1.1
E	Water use by the facility for alternate cooling systems, including:	§ 5.2, Table 5-3
1	Estimated maximum use, including the	Table 5-3

Authority	Required Information	Location of Required Content
	groundwater pumping rate in gallons/minute and surface water appropriation in cubic feet/second	
2	Estimated ground water appropriation in million gallons/year	Table 5-3, Appendix B
3	Annual consumption in acre-feet	Table 5-3, Appendix B
F	Potential sources and types of discharges to water attributable to operation of the facility	§ 6.4, Table 6-4, Appendix B
G	Radioactive releases, including:	–
1	For nuclear facilities, typical levels	N/A
2	For fossil-fueled facilities, the estimated range of radioactivity released by the facility in curies per year	§ 6.4, Appendix B
H	Potential types and quantities of solid wastes in tons per year at expected capacity factor	§ 6.4, Table 6-4, Appendix B
I	Potential sources and types of audible noise attributable to operation	§ 6.2, Appendix B
J	Estimated work force required for construction and operation	§ 6.14, § 7.6, Appendix B
K	Minimum number and size of transmission facilities required to provide reliable outlet	§ 5.8
7849.0330	The applicant shall provide data for each alternative that would involve construction of an LHVTL.	N/A

Authority	Required Information	Location of Required Content
A	for overhead transmission facilities:	–
1	schematic diagrams that show the dimensions of the support structures and conductor configurations for each type of support structure that may be used	Figure 5-4, Appendix E
2	a discussion of the strength and distribution of the electric field attributable to the transmission facility, including the contribution of air ions if appropriate	§ 6.5
3	a discussion of ozone and nitrogen oxide emissions attributable to the transmission facility	§ 6.1.2
4	a discussion of radio and television interference attributable to the transmission facility	§ 6.8
5	a discussion of the characteristics and estimated maximum and typical levels of audible noise attributable to the transmission facilities	§ 6.2
C	the estimated width of the right-of-way required for the transmission facility	§ 5.8
D	a description of construction practices for the transmission facility	§ 5.10.2
E	a description of operation and maintenance practices for the transmission facility	§ 5.13.2
F	the estimated work force required for construction and for operation and	§ 6.14

Authority	Required Information	Location of Required Content
	maintenance of the transmission facility	
G	a narrative description of the major features of the region between the endpoints of the transmission facility. The region shall encompass the likely area for routes between the endpoints. The description should emphasize the area within three miles of the endpoints. The following information shall be described where applicable	§ 6.10
1	hydrologic features including lakes, rivers, streams, and wetlands	§ 6.10
2	natural vegetation and associated wildlife	§ 6.10
3	physiographic regions	§ 6.10
4	land-use types, including human settlement, recreation, agricultural production, forestry production, and mineral extraction	§ 6.11, § 6.12
7849.0340	Alternative of no facility	§ 4.3.9
A	Expected operation of existing and committed facilities	§ 4.3.1
B	Description of the changes in resource requirements and wastes produced	Chapter 3, § 4.3.1, § 6.4, Table 6-4,
C	Description of possible methods of reducing environmental impact	Chapter 4, Chapter 6
Minn. Stat. § 216B.243	Certificate of Need Criteria	–
Subd. 2	Certificate required for this facility	Chapter 1
Subd. 3	Showing required for construction. In	–

Authority	Required Information	Location of Required Content
	assessing need, the Commission shall evaluate:	
1	Accuracy of the long-range energy demand forecast on which need is based	Chapter 3, Appendix A
2	Effect of existing or possible conservation on long-term demand	§ 3.1.1, Appendix C
3	Relationship of proposed facility to overall state energy needs, as described in most recent state energy policy report	§ 8.1
4	Promotional activities that may have given rise to the demand for this facility	§ 3.1.1
5	Benefits of this facility, including uses to protect or enhance environmental quality, increase reliability of energy supply	Chapter 6, § 7.1
6	Possible alternatives for satisfying demand, including increased efficiency and upgrading existing generation, load-management and distributed generation	Chapter 4
7	Policies, rules and regulations of other state and federal agencies and local governments	Chapter 1, Chapter 8
8	Feasible combination of energy conservation improvements, that can replace or compete with the facility	Chapter 3, § 4.3.6
Minn. Stat. § 216B.243 subd. 3a and Minn. Stat. § 216B.2422 subd. 4	Availability of renewable energy alternatives	§ 4.3.8

Authority	Required Information	Location of Required Content
Minn. Stat. § 216B.1694, subd. 2(A)(5)	Innovative energy projects	§ 4.3.8
Minn. Stat. § 216B.2426	Opportunities for Distributed Generation	§ 4.3.7

1 Summary

1.1 Introduction

Pursuant to Minnesota Statutes Section 216BC.243 and Minnesota Rules Chapter 7849, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), is pleased to submit this Application to the Minnesota Public Utilities Commission ("Commission") for a Certificate of Need for the Black Dog Generating Plant ("Plant") Repowering Project ("Project" or "Black Dog Repowering Project") and the associated transmission necessary for the direct interconnection of the Project. The Plant is located in Burnsville, Minnesota as shown in Figure 1-1.

The Project consists of replacing the remaining coal-fired generating Units 3 and 4 at the Plant with about 700 megawatts ("MW") of natural gas-fired, combined cycle, generation located in what is now the coal storage yard. The total output of Black Dog Units 3 and 4 was summer rated at 253 MW for the operating year 2010. As part of the Project, these units will operate solely on natural gas starting in 2013, during construction of the proposed facility, and be shut down in 2016 after the new combined cycle facility is placed in service. The Project results in a cost-effective way to meet customer load growth, removes older coal generation (and its associated emissions profile) from our portfolio, takes advantage of a unique opportunity to maximize the use of and increase capacity at an important existing generating site, and provides significant environmental and economic benefits to our customers and the region.

Repowering the Plant is the most cost-effective way to meet our customers' growing needs.

Our forecasts predict that customer demand will continue to grow at the rate of approximately 1.1% or about 110 MW per year even after consideration of our growing demand side management ("DSM") programs. To maintain reliable service to our customers, the Company needs to add approximately 470 MW of generating capacity to our system in the 2016 timeframe. After evaluating a number of options, our analysis concludes that the additional capacity from repowering Black Dog with a new combined cycle facility is the most cost-effective means to meet our customers' needs.

The Black Dog Repowering Project is a cost-effective means of modernizing our fleet.

The Project allows the Company to retire older, less efficient generation that would require significant investments to continue operating and meet pending environmental performance requirements. Black Dog Units 3 and 4 were constructed in 1955 and 1960 and have served our customers well for over 50 years. Like any aging generating facility, performance has started to decline and we face the increasing risk of major equipment failure. We expect something on the order of $200 million will be required to refurbish and maintain safe reliable operation over the next decade or two. Furthermore the U.S. Environmental Protection Agency ("EPA") is in the process of establishing new air quality performance requirements that could require approximately $200 million in new pollution control equipment on Units 3 and 4.

The Black Dog Repowering Project is the most cost effective way to address the combination of growing demand and aging infrastructure. We can provide more economical power by shutting down Units 3 and 4 and replacing the output with a new state-of-the-art, natural gas, combined cycle facility that also provides additional generating capacity to meet growing customer needs. A new combined cycle power plant operates much more efficiently and will modernize our generating fleet to serve our customers well into the future.

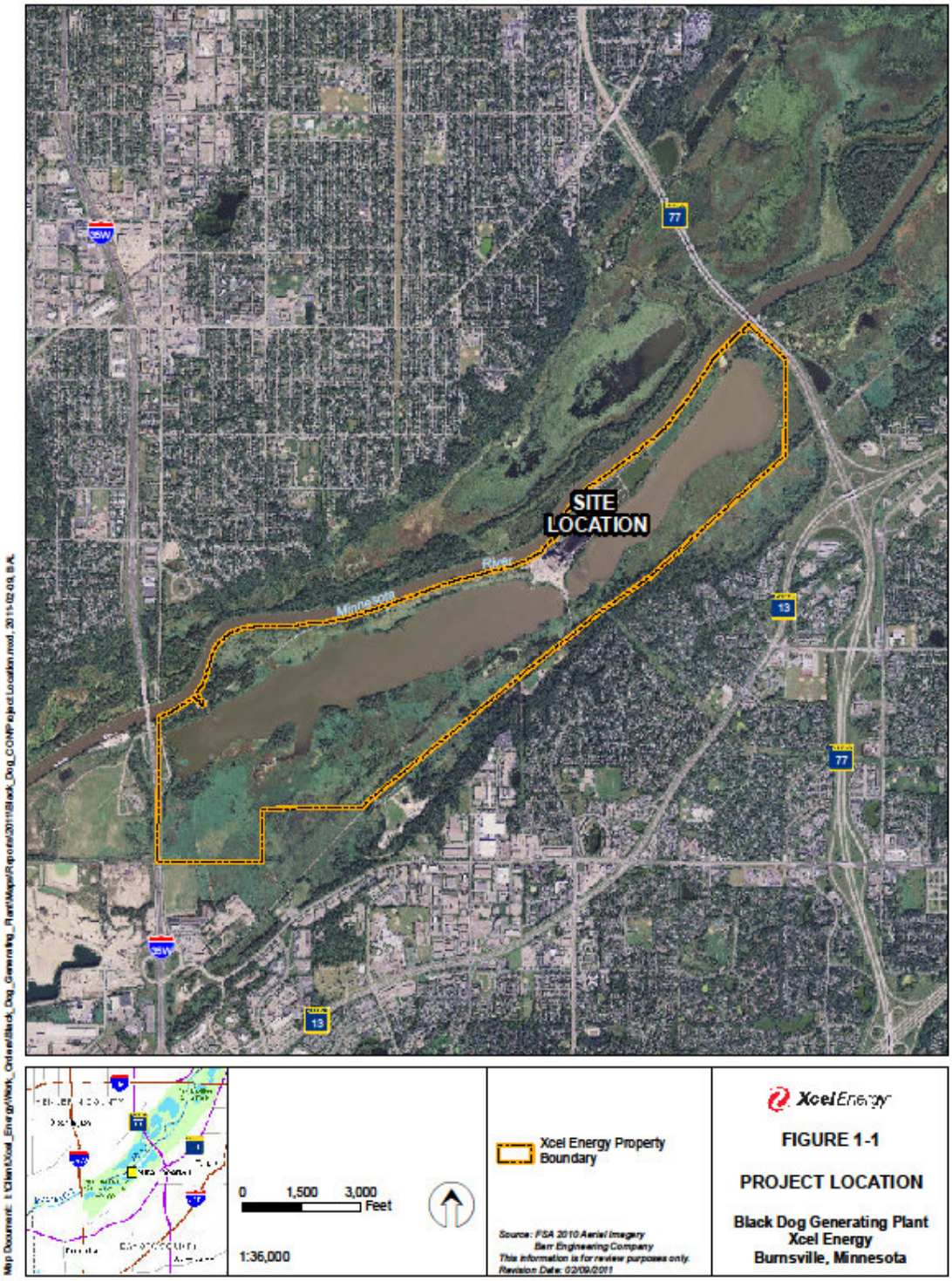
The Black Dog Repowering Project provides important system operating benefits.

Given today's mix of resources on our system, the Project provides a number of system performance and operating benefits. Because of the Plant's close proximity to the metropolitan load center, maintaining generation at this Plant site provides important system reliability and lower transmission line losses. The Project also provides additional operating flexibility to economically respond to fluctuations in customer demand and the variability of wind generation. The Project continues the Company's long and successful strategy of maintaining a diverse mix of generating resources with a variety of primary fuels including gas, coal, nuclear, wind, solar, and hydro, which reduces risks associated with overdependence on any one type of resource.

Repowering at the Black Dog Plant improves system environmental performance and provides a unique opportunity to take advantage of an existing generating site.

This Project will improve the environmental performance of our system. System carbon dioxide ("CO_2"), sulfur dioxide (SO_2"), mercury ("Hg"), nitrogen oxides ("NO_x") and particulate matter emissions will be lower by adding this Project versus any of the other alternatives we studied to meet customer needs. The existing Black Dog site already provides access to transmission lines that pass through the site. The Company holds the necessary transmission system rights to deliver power from this Project to customers upon completion of planned Midwest Independent System Operator ("Midwest ISO") Midwest Transmission Expansion Plan ("MTEP") projects. Since the Project will be developed at an existing site, there is little land use impact. Land use patterns have grown up around the Plant with its substantial buffer of nearly 1900 acres over decades. Conversely, it may be difficult to fully utilize the site in the future if the opportunity to repower the Plant is not taken advantage of today.

Figure 1-1: Project Location



1.2 Regulatory Framework

1.2.1 Certificate of Need

This application begins the Commission's review of our Project and an examination of alternatives. The Project meets the definition of a "large energy facility" as defined in Minnesota Statutes Section 216B.2421, subdivision 2(1) and a "large electric generating facility" as defined in Minnesota Rule 7849.0010(13) and thus requires a Certificate of Need from the Commission before construction can begin. Furthermore, Minnesota Statutes Section 216B.243 requires a Certificate of Need be obtained before increasing the generating capacity of a plant by more than 10% or 100 MW. Our proposal exceeds both thresholds.

To ensure that the Project is the best alternative to meet customers' needs, the Commission has developed procedures that allow other providers the opportunity to offer their alternative generating proposals as part of the Certificate of Need proceeding. *See Order Establishing Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, subd. 5 and Requiring Compliance Filing*, Docket No. E-002/RP-04-1752 (May 31, 2006); *see also Order Approving Five-Year Action Plan as Modified and Setting Filing Requirements*, Docket No. E-002/RP-07-1572 (Aug. 5, 2009). Under the type of process contemplated in the Commission's prior orders, the Commission will set a deadline for developers to intervene with competing proposals, we recommend June 1st, and notice will be published. If competing proposals are tendered, the Commission's process calls for a hearing to be conducted by an Administrate Law Judge to develop a record that examines the need for generation and the merits of the alternatives. The Company supports following such a process in this instance.

1.2.2 Siting and Environmental Review

Pursuant to Minnesota Statutes Section Chapter 216E, the Project meets the definition of a large electric power generating plant ("LEPGP") and requires a Site Permit. The section of 345 kV transmission required to connect the new units to the transmission system, while entirely contained on the site, meets the definition of a high-voltage transmission line ("HVTL") and we will seek a Route Permit. The Commission must issue Site and Route Permits before construction can begin.

We plan to file a combined Site Permit and Route Permit application by early May 2011. Typically the Commission then consolidates the Certificate of

Need, siting and routing proceedings. Since we are proposing to repower at an existing site, the siting process places primary emphasis on the examination of the potential environmental and land use impacts of our Project and alternatives rather than siting options. The Department of Commerce's Office of Energy Security ("OES") will prepare an environmental review document called an Environmental Assessment as part of these regulatory proceedings.

There will be several opportunities for the public to comment on the need for the Project, alternatives to meet the need, and potential impacts of the Project. Our applications will be posted on our web site at http://www.xcelenergy.com/Minnesota/Company/Pages/Home.aspx. Any interested party can subscribe to receive notice of any documents filed in the proceeding by registering at:
https://www.edockets.state.mn.us/EFiling/security/login.do?method=showLogin

1.2.3 Environmental Permits

In addition to the Certificate of Need, siting and route permitting processes, the Project must also obtain permits from the Minnesota Pollution Control Agency ("MPCA") and the Minnesota Department of Natural Resources ("MnDNR") in regards to water use and air and emissions. A more expansive discussion of other regulatory requirements is presented in Chapter 2 of this application.

1.3 Demand and Supply Need

The Black Dog Repowering Project is needed to address two developing inadequacies or needs on our system:

- *Demand:* Our forecasts predict that the demand for electrical power will continue to grow as population increases and our economy expands. Generation capacity deficits start to show up in 2014 based on a median forecast. By 2016, demand could exceed the ability of the existing system to reliably deliver power by over 470 MW, even after accounting for our aggressive DSM programs.

- *Supply:* Black Dog Units 3 and 4 are among the oldest generating plants on our system. They have served the system well for over 50 years. Our estimate of a shortfall in capacity by 2016 assumes Black Dog Units 3 and 4 will continue to operate. However, our analysis also

indicates the investments necessary to extend their life and to meet pending environmental performance standards make it unlikely they can continue to operate as economically as a newer facility. We conclude that our generating system will likely be more efficient and economical if we cease to operate Black Dog Units 3 and 4 and replace the 253 MW of generation with a new facility.

Repowering at the Black Dog Plant with a new, state-of-the-art, natural gas, combined cycle facility is a very advantageous, cost effective way to address the combination of these two needs.

1.3.1 Demand

The Company has service territory in five upper Midwest states and designs, plans and operates an integrated five-state system. As a result, our forecasts address resource and customer needs for our entire service territory of Minnesota, upper Michigan, North Dakota, South Dakota and Wisconsin combined.

We currently project energy growth of 0.9% or approximately 440 GWH per year for the 2011 to 2025 forecast period. During this period, peak demand increases at an average annual growth rate of 1.1% or about 110 MW per year. These estimates incorporate the expected effects of our DSM programs.

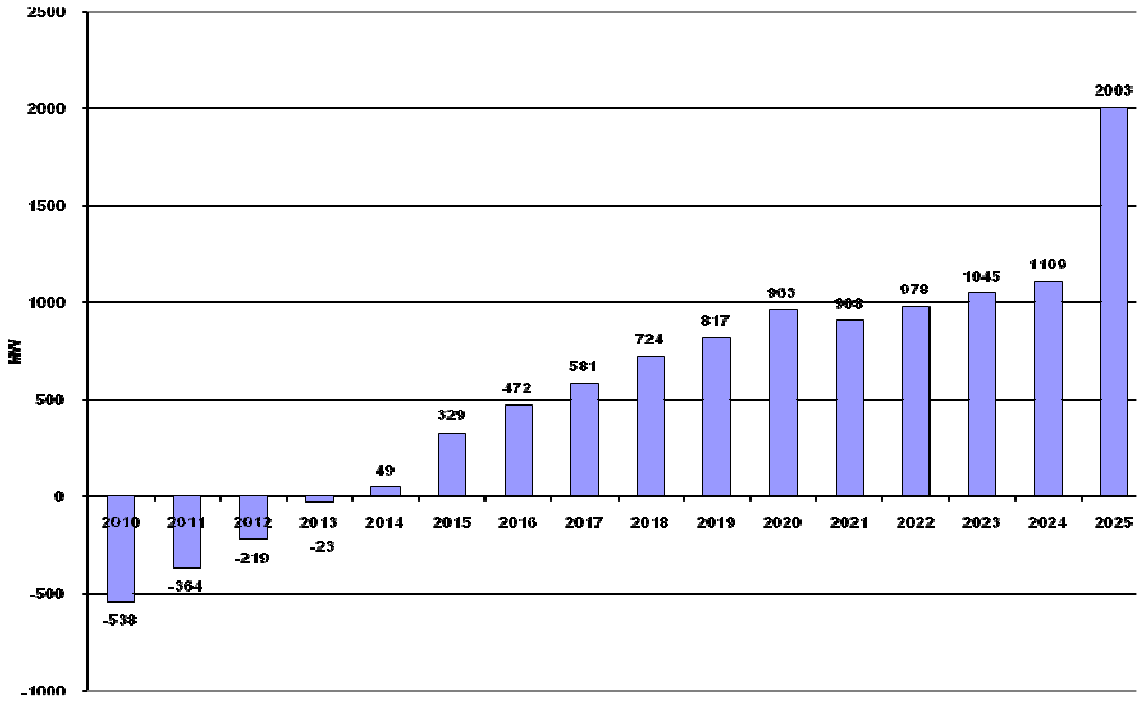
We have worked with the Commission to establish stretch goals for our DSM programs. We are committed to increasing our DSM achievements to 1.5% of sales as presented in our 2010 Resource Plan. Our DSM programs are forecast to reduce peak demands during the summer peak periods by approximately 1060 MW during each year over the planning period. The resource need we have presented in this application assumes we will continue to be successful in these efforts.

Another way in which we can manage resource requirements is by participating in regional reliability groups. By doing so, the total amount of generation necessary to ensure reliability can be minimized. Utilities together with the Midwest ISO have established a 12% reserve margin. Each utility is required to have generation resources 12% higher than peak customer demand. We add the reserve margin into our forecast after accounting for DSM.

Our forecast also includes the assumption that our contracts with Manitoba Hydro do not expire in 2015 and are extended to 2025, providing us with 725

MW of power from 2015-2021 and, potentially, going up to 850 MW in 2021. In addition, the forecast includes 230 MW of capacity increases at our nuclear power plants based on uprate projects that are underway or planned to occur during the next several years. As shown in the figure below, we will need additional generation in the 2015 to 2016 time frame in order to maintain a reliable system.

Figure 1-2: Forecasted Resource Needs by Year



Forecasts are a picture of the future based on what we know today. As a result, we use probability analysis to develop higher and lower forecasts to test the potential impacts of different futures. In Chapter 3 we discuss our forecasts in more detail.

1.3.2 Supply

Our assessment of need assumes Black Dog Units 3 and 4 will continue to be available to generate 253 MW of power throughout the next decade and beyond. However, after examining the condition and performance of the two coal fired units and the investments that will likely be necessary to keep the

units operating, we have concluded our power supply may be more cost effective if we cease operating Units 3 and 4 and replace their output as part of our plan to meet growing demand.

Black Dog Units 3 and 4 are over 50 years old. The boilers, turbines and generators are essentially original pieces of equipment that have been well maintained and operated over this entire time period. However, as one would expect from 50-year-old assets, operating data shows declining availability. If the units are to be operated another 20 years, major equipment repairs and/or replacements will likely be required for the turbines, generators, boiler sections, feedwater heaters, pumps and electrical equipment. We estimate over $200 million will likely be needed to refurbish and/or replace aging equipment.

These units will also require substantial upgrades to their pollution control systems to continue to operate. The EPA is in the process of establishing major regulatory changes covering air, water and waste standards. It appears new environmental performance standards may require over $200 million in pollution control upgrades to keep Units 3 and 4 running.

In total, therefore, over $400 million would need to be invested to keep Units 3 and 4 operating on coal at their current capacity ratings. We believe that this capital would be better spent replacing these units with a significantly larger natural gas-fired, combined cycle facility that will also better serve increases in customer demand.

1.4 Analysis of Alternatives

The Black Dog Repowering Project is the most cost effective solution to meet our system need. In Chapter 4 we present the analysis of alternatives that leads us to this conclusion. After evaluating a number of alternatives qualitatively, four different approaches to meeting our system needs were studied quantitatively.

- Life extension: Invest to continue to operate Black Dog Units 3 and 4 and add additional new generation elsewhere on the system to meet growing demand.
- Repower: Cease operating Black Dog Units 3 and 4 and repower at Black Dog with about 700 MW of combined cycle generation.

- Alternative Generation: Cease operating Black Dog Units 3 and 4 and develop additional generation elsewhere on the system to replace it and meet growing demand.

- Renewable Generation: Cease operating Black Dog Units 3 and 4 and develop 700 MW of biomass fueled capacity.

Cost and performance information was developed for each of these alternatives. System cost impacts were simulated using the Strategist resource expansion model. Strategist simulates the operation of our entire generation system over the long term and adds generating resources to meet growing customer needs in the most cost effective way.

We first compared the merits of the alternatives without assigning any externality values for air emissions and without assigning values for the risk of future greenhouse gas ("GHG") regulation. The results indicate that it is in customers' best interests to repower at the Plant. This alternative is superior to developing the needed generation elsewhere. The present value of system capital and operating costs over time from the Strategist model were lowest with the proposed Black Dog Repowering Project. Even if a biomass resource could be developed as modeled, system costs were substantially higher.

We also conducted a number of tests to explore how sensitive the analyses were to the assumptions used. For example, we explored how sensitive the costs of the Project were to a range of possible values associated with GHG regulation. Higher and lower demand forecasts, varying capital cost estimates and fuel price assumptions were also tested. None of the sensitivity testing changed the ranking of the alternatives.

In order to provide further assurance that our Project is the best fit for the need, the Commission has established procedures that provide independent power producers the opportunity to intervene in the Certificate of Need process with competing power purchase proposals. If a competitor's project provides a better fit, that project will be selected over the Company's Project. It will be important then that all the potential costs to customers associated with competing proposals be included in the Commission's decision making.

For example, power purchase alternatives from independent power suppliers may result in significant indirect costs to customers that, if present, will need to be included in any project cost comparisons. Accounting standards require long term power purchase agreements associated with certain types of

resources to be treated as capital leases that must be recognized as long term debt. Such accounting treatment will have significant impacts on the Company's capital structure and will increase the financing costs for the Company which in turn will increase customers' costs. Lease accounting treatment results in very real costs to our customers that need to be factored into the analysis. As discussed further in Section 4.3.2, if competing proposals are tendered in this proceeding, it will be important to evaluate the impact of lease accounting standards to make a complete and thorough analysis of alternatives.

1.5 Project Description

The Project's two combustion turbine-generator sets, two heat recovery steam generators ("HRSGs"), and one steam turbine-generator will be located within a new 425 foot by 280 foot by 140 foot tall building in the current coal yard area. Two air inlet filters will be located on the exterior of the structure and five new transformers will be located adjacent to the building. A new 345 kV substation will be constructed next to the generation block. Three water tanks and two ammonia storage tanks will also be added outside the new Plant structure. The exhaust stacks will be approximately 230 feet tall and will be located adjacent to the new structures. Two double circuit 345 kV transmission lines will connect the substation to existing transmission lines passing through the Black Dog plant site on the south side of Black Dog Lake. The new transmission structures will be between 90 and 110 feet tall. A cooling tower will be located where the current ash ponds reside. The cooling tower will be approximately 70 feet tall.

1.5.1 Fuel

The Project will be fueled entirely by natural gas with no backup fuel. We plan to secure firm natural gas supply contracts through a competitive bidding process. Any needed gas pipeline improvements and associated approvals will be the responsibility of the supplier.

1.5.2 Construction Schedule

Generation block construction will begin after approvals are obtained. Site preparation and fill to bring the Project area above the 100 year flood level is anticipated to start in 2012. Shortly thereafter we will discontinue the use of coal at Black Dog Units 3 and 4 and use natural gas. Installation of pilings

and construction of foundations will start the following year. Building erection and installation of the large components would occur in 2014. Transmission construction is expected to occur in 2014. In 2015 construction completion and startup of the facility would occur. The combined cycle facility is expected to be in commercial operation by January 2016. We will cease operation of Black Dog Units 3 and 4 once the Project is operating.

1.5.3 Operation

The Project will be integrated into our remote dispatch control center. We expect to use the Project's capability without duct firing (and maximum efficiency point) for intermediate load service, dispatching it after all incrementally more economical and "must run" units have been dispatched. The additional capacity of the Project, available through supplemental firing of the HRSG, will be utilized for peak demand periods.

The Project will also serve to load follow as system load requirements change and compensate for intermittent or variable non dispatchable generation such as wind power. The Project will be able to commence start up after a 30-minute notice and will have the ability to ramp at approximately 5 to 10 MW per minute depending on the pre-existing steam turbine condition.

The Project is expected to be dispatched 5 days per week, 16 hours per day with an initial annual capacity factor of 35%. It is expected that the capacity factor will rise to higher levels as system demands increase.

1.5.4 Cost

We estimate the capital cost of the facility will be approximately $600 million. More detailed cost information has been designated as trade secret since it could be used by independent power producers to design competing power purchase proposals. Access to capital and operating cost information could conceivably result in proposals at higher rates than might otherwise be offered. Capital costs include the repowered plant costs, substation costs, interconnecting transmission line costs and the incremental costs of a cooling tower attributable to the Project. In our examination of alternatives in Chapter 4 we also describe some of the contingencies that may affect the cost of the facility.

Our cost estimates are based on the Project schedule summarized above. Delays could significantly affect the actual costs. We look forward to working with the Commission and OES staffs and interested parties to achieve the permitting milestones necessary to keep the Project on schedule.

1.6 Environmental Performance

Chapter 6 of this application provides a discussion of the environmental performance of our Project. The Black Dog Repowering Project has been designed to meet all the requirements necessary to obtain air and water permits. As the result of the Black Dog Repowering Project, emissions will be reduced in a major metropolitan area and the overall environmental performance of our system will be improved.

1.6.1 Air

Natural gas-fired combined cycle technology is among the most efficient and cleanest means of generating fossil fired utility-scale electricity. Natural gas combustion generates significantly less CO_2, particulate matter, SO_2, and toxic air emissions (including Hg) than oil or coal.

The primary constituents of concern resulting from combustion of natural gas are NO_x, carbon monoxide ("CO") and volatile organic compounds ("VOCs"). The Project will control NO_x emissions through use of dry low-NO_x burners and selective catalytic reduction systems ("SCR"). Good combustion practices and oxidation catalysts will be used to control emissions of fine particulates, CO, and VOCs.

Preliminary estimates are that NO_x, SO_2, and Hg emissions will be reduced 96 to 99% on an annual basis, and that particulate matter and carbon dioxide emissions will be reduced 50 to 65% on an annual basis as compared to current operations. The Project will result in reduced GHG emissions and contribute to our ability to implement the GHG emission reduction goals envisioned by Minnesota Statutes Section Chapter 216H.

1.6.2 Water

Water usage associated with operation of the Project will be similar to that of the existing Plant and will not have a major impact on water supplies or water quality after discharges. Surface water appropriated from the Minnesota River is currently used for cooling water and will be used to supply the cooling water for the Project as well. The total surface water appropriations for the site will be within the existing Water Appropriations Permit (#1961-0270) limitations. For once-through cooling, the withdrawal rate will be higher than recent years but similar to operations of the Plant in the late 1990's. A closed cycle operating mode with a cooling tower would result in significantly lower withdrawal volumes.

Groundwater from the existing well will supply other water needs for the Project. No increase in the groundwater appropriation rate or annual withdrawal volume will be required for the Project.

1.6.3 Noise

Noise from the generating units is not expected to have a significant impact. The generating units will be in compliance with state noise standards. The generation is located in an isolated area with the nearest residences located more than 1,500 feet away from the Plant. Noise from the operation of the Project is expected to be predominantly low frequency noise, as is noise from traffic. Noise from the generation operations will not significantly impact the acoustical environment given the noise control technology that will be employed by the new generating units. In addition, we will cease operating the existing Units 3 and 4 along with the noise associated with coal trains and other coal and ash handling processes.

1.6.4 Land Use

The Black Dog Repowering Project takes advantage of an existing site and does not create new land use impacts. The Plant is located on a 35 acre parcel which is well buffered within an approximately 1900 acre area owned by the Company. The transmission necessary to connect the Project to the transmission grid will be built on Company property and will not require easements from private landowners.

1.7 Certificate of Need Criteria

The criteria the Commission will use to evaluate our Certificate of Need request are contained in Minnesota Statutes Section 216B.243 and in Minnesota Rules Chapters 7849 and 7829. A Certificate of Need must be granted to an applicant upon determining that four principle criteria of Minnesota Rule 7849.0120 are met. They are:

> *A. The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states…,*

The demand for electricity on our system continues to grow. Without this additional generation we anticipate inadequate generating resources to reliably and efficiently meet our obligation to serve. The Project provides about 450

MW of incremental capacity in a time frame when our forecasts show a capacity deficit.

> B. *A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record…,*

Our analysis of alternatives demonstrates that the most cost effective way to meet our resource needs is to cease operating Black Dog Units 3 and 4 and repower at the Plant site with about 700 MW of natural gas combined cycle generation. Furthermore the addition of generation at a site within the metropolitan load center provides important system benefits. The opportunity for competing proposals as part of the Certificate of Need process will help ensure the Commission's decision will be in customers' best interests.

> C. *By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health…,*

The Black Dog Repowering Project is the most cost effective solution to maintain reliable service to our customers. It provides significant socioeconomic benefits by helping to keep the cost of energy as low as reasonably possible. The Project takes advantage of an existing site to minimize impacts to the natural and man made environment. Repowering at the Black Dog Plant site at the same time we cease operation of Units 3 and 4 provides a unique opportunity that may not be available in the future.

> D. *The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.*

The Black Dog Repowering Project will be designed to meet all water use, air quality and water quality standards necessary to obtain operating permits. The Project will result in continued improvement in the overall environmental performance of our generating fleet and help us continue to make progress toward the environmental policy goals of the state.

We believe our Project best satisfies these four criteria and respectfully request the Commission grant our request for a Certificate of Need.

2 General Information and Regulatory Permits

2.1 Applicant Information

The applicant's complete name and address, telephone number, and North American Industry Classification System ("NAICS") and Standard Industrial Classification ("SIC") codes are:

Northern States Power Company, a Minnesota corporation ("Xcel Energy")
414 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-5500
NAICS: 221119
SIC: 4911, 4922

The official or agent to be contacted regarding the filing is:

Sara J. Cardwell
Manager, Regulatory Administration
Xcel Energy
414 Nicollet Mall, GO 7
Minneapolis, MN 55401
(612) 330-7975

2.2 Description of Business and Service Area

Northern States Power Company is a public utility under the laws of the state of Minnesota. The legal name of Xcel Energy is Northern States Power Company ("NSP"), a Minnesota corporation. NSP and its parent public utility holding company, Xcel Energy, are headquartered in Minneapolis, Minnesota.

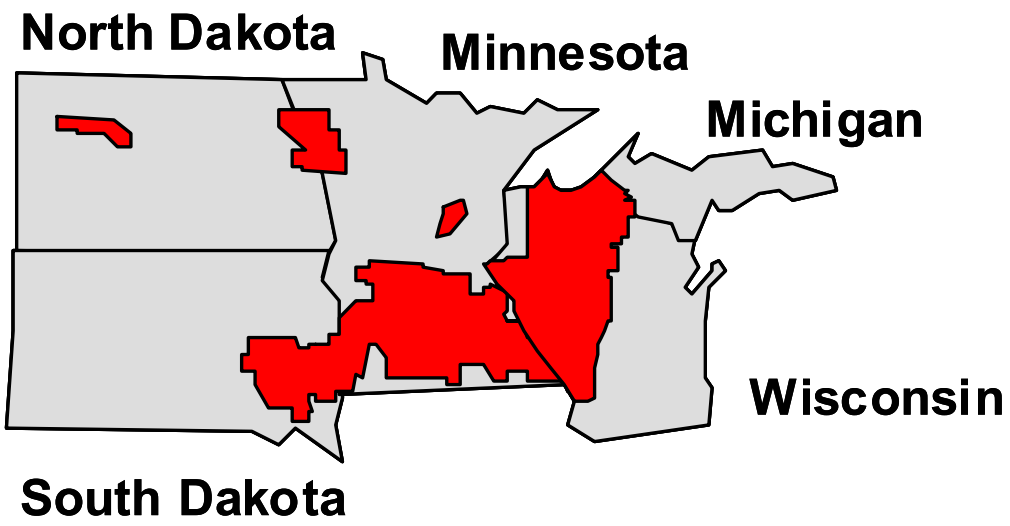
Xcel Energy is a public utility that generates electrical power, and transmits, distributes, and sells it to residential and business customers on an integrated system basis within service territories assigned by state regulators in parts of Minnesota, South Dakota, and North Dakota, with our affiliate utility serving portions of Wisconsin and the upper peninsula of Michigan. The Company owns and operates a number of electric generation facilities serving this area using a variety of technologies and fuels including, wind, coal, oil, natural gas, hydro, refuse derived fuel ("RDF") and nuclear. Additional wind, landfill gas,

biomass and additional hydropower are also included in our generation portfolio through purchased power agreements ("PPAs").

Xcel Energy's integrated system has 1.5 million electricity customers in the upper Midwest. Figure 2-1 shows the Company's upper Midwest service territories in the states of Minnesota, Wisconsin, Michigan, North Dakota and South Dakota.

The Black Dog Generating Plant is owned and operated by Northern States Power Company.

Figure 2-1: Xcel Energy Upper Midwest Service Territory



2.3 Certificate of Need Process and Competitive Acquisition

The Commission indicated in the Company's 2004 and 2007 Resource Plan dockets that the Company should rely on competitive processes as much as possible to meet resource requirements. Thus, the Company has conducted a number of competitive bidding processes to acquire new resources. Competitive bidding involves issuing formal Requests for Proposals, reviewing proposals received from developers, selecting the most cost effective projects, negotiating purchase agreements and requesting the Commission's review and approval of the purchase agreements. However when an opportunity to rehabilitate an existing Company-owned site such as that provided by the Black Dog Repowering Project presents itself, the competitive bidding process does not work well.

In the 2004 Resource Plan Docket, parties developed and the Commission approved an alternative process that takes some of the elements of competitive bidding and applies them when the Company proposes new generation.

This alternative process, which is referred to as the "Track Two" process, ensures that independent developers have the opportunity to offer competing generation proposals as part of a Certificate of Need proceeding. Developers that want the Commission to consider a competing proposal must intervene in the Certificate of Need proceeding. After the developer provides the information necessary to evaluate their alternative, the Commission refers the matter to the Office of Administrative Hearings for a contested case proceeding.

The purpose of a contested case proceeding is to develop a record that establishes need and evaluates and compares the merits of the alternatives. An Administrative Law Judge presides over the hearing and makes a recommendation. The Commission then makes its decision to grant the Company a Certificate of Need, which in this case would authorize the Black Dog Repowering Project or to direct the Company to negotiate a power purchase agreement with the successful competing developer.

The main steps of the Track Two process are summarized below:

A) The Company initiates the process with a Certificate of Need filing that identifies the size, type and timing of the resource need and seeks approval for the selected resource to fill this need. The filing contains the information necessary to evaluate the proposal and sufficient information to allow prospective competitors to make alternative proposals.

B) The Commission establishes a procedural schedule to provide adequate time for alternative proposals to be prepared. The Commission also approves a plan to provide notice that will encourage the submittal of alternative proposals.

C) The Company provides additional notice as directed by the Commission to facilitate the submittal of alternative proposals. Notice provides prospective competing developers the information and direction needed to provide complete alternative submissions to the Commission and the Company.

D) If competing proposals are submitted, a contested case hearing process is conducted before an independent Administrative Law Judge. The record of the proceeding, including findings and recommendations, becomes the basis for a selection decision by the Commission. To the extent that no competing proposals are submitted, the process would continue as a regular Certificate of Need proceeding, using the alternatives provided by the Company to evaluate the reasonableness of the Project.

E) If the Commission selects the Company's proposal, the Commission Order provides the requested approval.

F) If the Commission determines that one of the competitive alternatives is a better option, the Company is given a four-month period to negotiate a PPA. Following the negotiation period, the Company would file for approval of the PPA. If the parties are unable to reach an agreement, the Company must file an explanation and proposed next steps with the Commission.

G) For an approved PPA, the project would proceed to obtain any remaining permits, but a certificate of need would not be required per Minnesota Statutes Section 216B.2422, subdivision 5.

H) Upon receipt of all needed permits, the project proceeds to implementation.

2.4 Notices, Procedural Guidance and Schedule

Appendix D provides the guidance we propose to provide to prospective competitors for use in developing a proposal to submit to the Commission and the Company for consideration in this proceeding. As part of this guidance, we propose that intervening developers contact the OES with their questions. The OES provides an independent source to answer questions thereby ensuring effective communication, process transparency, and the even-handed application of requirements.

We have structured our guidance to provide flexibility to developers. Capacity amounts that differ materially from the Company's Project will be evaluated accordingly. We issued a press release commensurate with this filing on March 15, 2011 announcing the Black Dog Repowering Project.

Once the Commission establishes a deadline, we have proposed June 1, 2011, for competing submissions, we propose to distribute the supplemental notice outlined in Appendix D. The proposed supplemental notice informs potential developers that the Company has initiated the proceeding. The supplemental notice further explains the framework that will be used, the information required, and the deadline for proposals to be submitted to the Commission. Below is the list of media outlets we propose to use in our notification process.

Table 2-1: Publications List

Print News Media	**TV and Radio Media**
Megawatt Daily	Associated Press – Minneapolis
St. Paul Pioneer Press	KARE – TV
Minneapolis Star Tribune	KMSP – TV
Twin Cities Business Journal	KSTP – TV
Minnesota News Network	WCCO – TV
Dow Jones Newswires	WCCO – Radio
Platts Electric Power Newsletters	Minnesota Public Radio
Hydro Review Magazine	**Web Sites**
	Xcel Energy Web
	Dept. Of Commerce E-Dockets

2.5 Related Filings and Permits

In addition to a Certificate of Need, the Black Dog Repowering Project will require several other permits and approvals from the Commission, other state agencies and other authorities.

2.5.1 Site and Route Permits

Pursuant to Minnesota Statutes Chapter 216E, the Project meets the definition of a large electric power generating plant ("LEPGP") and requires a Site Permit. The section of 345 kV transmission required to connect the new units to the transmission system meets the definition of a HVTL and requires a Route Permit.

We plan to file the combined site and route permit application by early May 2011. There will be additional opportunities for the public to comment on the potential impacts of the Project as the OES will conduct one or more public hearings.

2.5.2 Gas Pipeline Routing Permit

The Company will issue an RFP for natural gas transportation. The selected provider will apply for a routing permit if needed in accordance with the requirements of Minnesota Statutes Section 216G.02 and Minnesota Rules Chapter 7852 as well as any other necessary permits for the gas pipeline construction and operation, such as the general National Pollutant Discharge Elimination System ("NPDES") Stormwater Permit for Construction Activity, if required by the pipeline project's estimated area of disturbance.

2.5.3 Transmission System Filings

Generator Interconnection Agreement
On September 10, 2010, Xcel Energy filed the required Generation Interconnection Agreement Request with the Midwest ISO to cover an expected capacity increase of up to 500 MW at the Black Dog Plant site. The Midwest ISO evaluates interconnection requests to determine if additional transmission system improvements will be needed to maintain reliable operation of the system. The study results could indicate additional transmission upgrades for interconnecting the Project are needed.

Transmission Service Request
On February 10, 2011, the Midwest ISO confirmed that the Company would receive firm transmission service to cover an expected capacity increase of up to 500 MW at the Black Dog Plant site, conditional on the completion of two previously planned Midwest ISO MTEP projects.

2.5.4 Environmental Permits

Air Emission Permit
We expect to file an application with the MPCA in spring 2011 for an amendment to the Plant's air emission permit, Permit No. 03700003-009, to accommodate the Project.

NPDES Discharge Permit
We will apply for an amendment to the Plant's existing NPDES discharge permit in late 2011 to modify the Plant's discharges. Modifications will entail the cooling water system and its discharges and the process water system and its discharges. The modifications will address the Project, the future operation of existing Unit 5/2[1] as well as ceasing operation of the existing Unit 3 and 4 components. In addition, an application will be filed with the Metropolitan Council Environmental Services ("MCES") for approval to direct some plant wastewater streams to sanitary sewer. Addition of an outfall structure to discharge to Black Dog Lake may also require obtaining a U.S. Army Corps of Engineers Section 10 Work in Navigable Waters and Section 404 Dredge and Fill Permit and/or a MnDNR Work in Protected Waters Permit.

NPDES Stormwater Program
The Project triggers the requirement to apply for coverage under the MPCA's NPDES Stormwater Permit Program for Construction Activities. We will prepare a Stormwater Pollution Prevention Plan ("SWPPP") and apply for coverage under a general permit prior to commencement of Project construction activities. We will require contractors to comply with the SWPPP and the stormwater permit.

For existing operations, the Plant maintains an Industrial Activity SWPPP as required by the Plant's NPDES permit. Prior to the Project's commercial operation, Xcel Energy will update the Industrial Activity SWPPP as necessary.

Section 404 Wetland Permit
Depending on extent of work in waters, some construction activities or components may require obtaining a U.S. Army Corps of Engineers Section

[1] In 2002, the original Unit 1 boiler/turbine and the Unit 2 boiler at the Black Dog facility were repowered with a natural gas-fired, combined cycle unit (Unit 5/2). Exhaust heat from Unit 5 powers the Unit 2 steam turbine.

404 Dredge and Fill Permit and/or a MnDNR Work in Protected Waters Permit.

2.5.5 Other Permits, Approvals or Notifications

The Project may also require permits, approvals or notifications under the following programs:

- Federal Aviation Administration Notice of Proposed Construction or Alteration (for exhaust stack and potentially other structures)
- MnDNR Crossing Permits for Associated Utilities (e.g. electric transmission lines, natural gas lines, sewer lines) by Xcel Energy or by the provider
- Floodplain Work Approval through Site Permitting
- Exemption to allow burning of natural gas for power production (DOE, 10 CFR 503)
- Road Crossing Permits (Mn/DOT, Minn. R. Chapter 8810)
- Endangered Species Act Review
- Miscellaneous State Building and Construction Permits and Inspections (Minn. Stat. § 216E.10, Subd. 2)

We also plan to work closely with local governments and other officials to address any reasonable concerns they might have as we move forward with the Project in our Site and Route Permit processes.

3 Demand and Supply Need

The Commission must determine that four principal criteria are met when granting a Certificate of Need (Minn. R. 7849.0120). This Chapter addresses the first criterion (Subpart A) that:

"the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states."

The Black Dog Repowering Project, or a suitable alternative, is needed to address two developing inadequacies or needs on our system:

- *Demand:* Our forecasts predict that customers' demands will continue to grow. Generation capacity deficits start to show up in 2014 based on a median forecast. By 2016, demand could exceed the ability of the existing system to reliably deliver power by approximately 470 MW after accounting for our DSM programs.

- *Supply:* Black Dog Units 3 and 4 are among the oldest generating units on our system. They have served the system well for over 50 years. Our estimate of a shortfall in capacity by 2016 assumes Black Dog Units 3 and 4 will continue to operate. However, our analysis indicates the investments necessary to extend their life and to meet evolving environmental performance standards make it unlikely they can continue to operate as economically as a newer facility. We conclude our generating system can be made more efficient and economical if the 253 MW of generation from the existing Black Dog Units 3 and 4 is supplied by a new facility that also fulfills the need for additional capacity.

3.1 Demand and Energy Forecasts

The Company designs, plans and operates a five-state integrated system. As a result, our forecasts address resource and customer needs for our combined service territories in Minnesota, Michigan, North Dakota, South Dakota and Wisconsin. We forecast the number of customers and energy sales by customer class for each of the five state jurisdictions separately and then aggregate them. Serving our customers in this five state area on an aggregated basis reduces overall system costs and increases system reliability.

The use of a five-state system forecast is appropriate and consistent with the methodology used in our resource planning and all other generation related Certificate of Need applications we have filed. Therefore, the growth of our system depicted in this chapter is the five-state system forecast.[2]

Our forecast of peak demand in our five-state upper Midwest system is shown below in Figure 3-1. Figure 3-2 below illustrates our forecast of energy consumption. The methodology used to develop the forecast demand and other forecast details required by Minnesota Rule 7849.0270 are provided in Appendix A. The forecast in Figures 3-1 and 3-2 incorporates the DSM savings goal approved in our 2010-2012 Triennial Conservation Improvement Plan ("CIP").

We project energy growth of 0.9% or 444 GWh per year for the 2011 to 2025 forecast period. During this period, the median base peak increases at an average annual growth rate of 1.1% or approximately 110 MW per year.

[2] Minn. R. 7849.0270, subp. 2 (A) and subp.. 3 and Minn. R. 7849.0270 subp. 3(D) require the submittal of the statistical tests for the forecast used. Since Xcel Energy forecasts peak demand and energy for the five-state system by customer class for each state jurisdiction, the data is voluminous (>1,000 pages). Therefore, we have not included the information required by Minn. R. 7849.0270 subp. 3(D) with this application, but will provide it on CD upon receiving an information request from the OES or any other parties to this proceeding.

Figure 3-1: Median Base Summer Peak Demand (MW)
NSP System with 1.15% Retail Sales DSM Adjustment

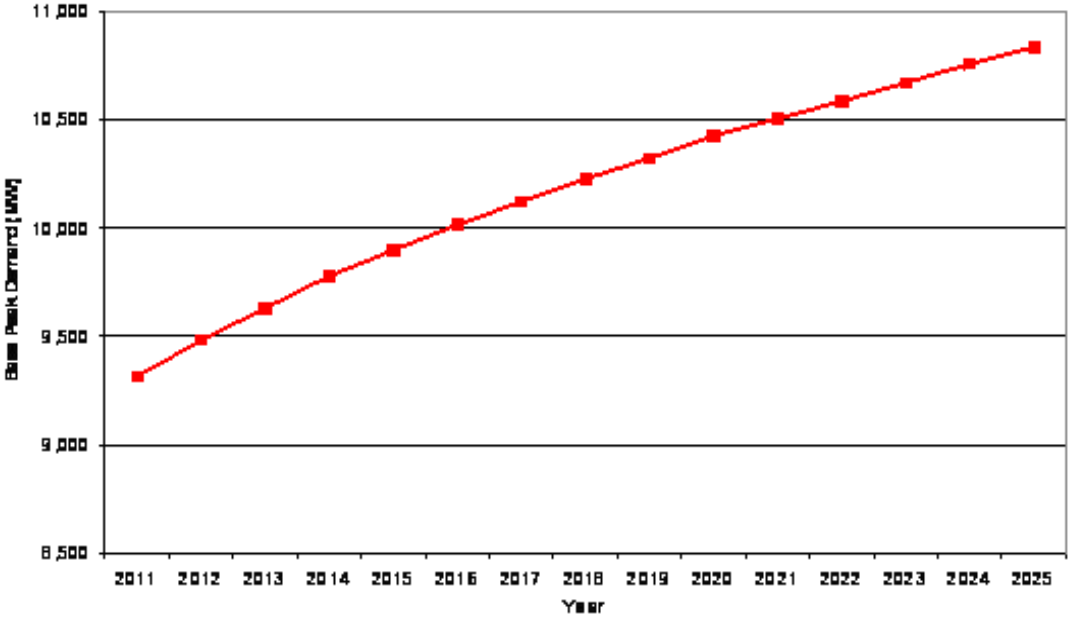
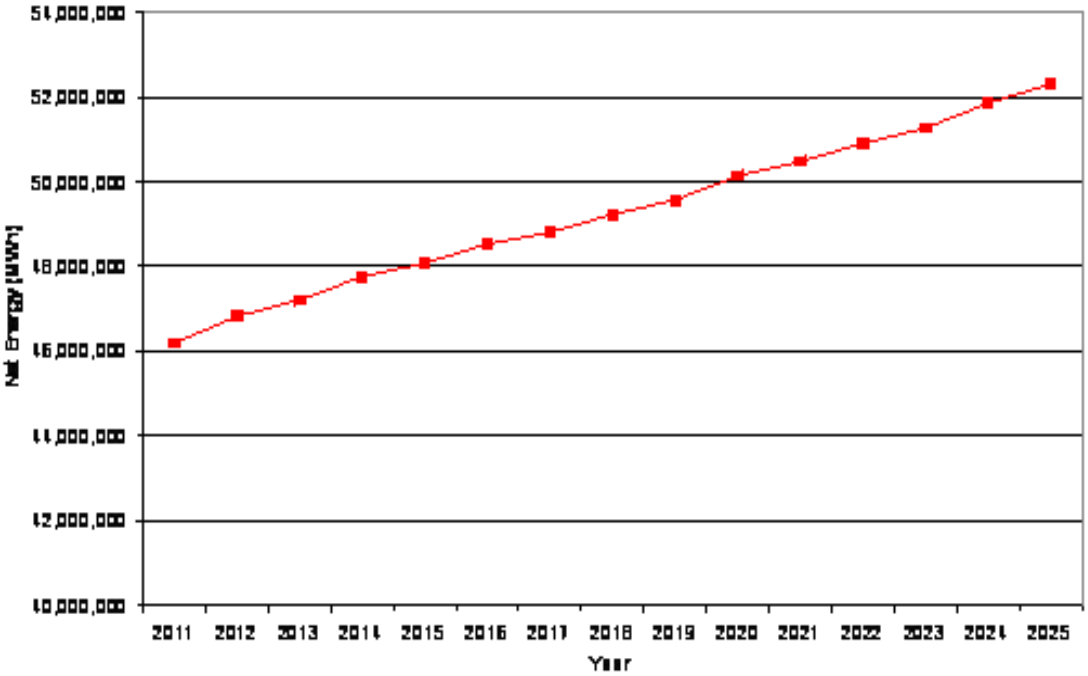


Figure 3-2: Median Net Energy (MWh)
NSP System with 1.15% Retail Sales DSM Adjustment



3.1.1 Forecasts Incorporate DSM

Our forecasted demand is not growing as a result of promotional activities to sell electricity. We do not have programs promoting the sale of electricity – we have programs that promote the conservation of electricity. Our forecast incorporates the peak demand and energy savings goals estimated in our most recent CIP Triennial Plan. Our resource need analysis in our 2010 Resource Plan assumes we achieve a 1.15% reduction in sales from DSM programs in 2010, 1.2% in 2011, and 1.3% in 2012 and thereafter. As we discuss in our 2010 Resource Plan, we propose to fully implement our 1.3% savings goal and work toward meeting the state goal of 1.5% in DSM savings over the next several years. And, in fact, our preliminary results for 2010 indicate we may achieve a 1.3% savings, or over 400 GWhs for the year.

In order to meet our DSM goals, we devote significant resources to our DSM programs. Between 1990 and 2009, Xcel Energy spent over $754 million (nominal) on Minnesota DSM efforts and saved over 5,027 GWh of energy and 2,442 MW of demand.

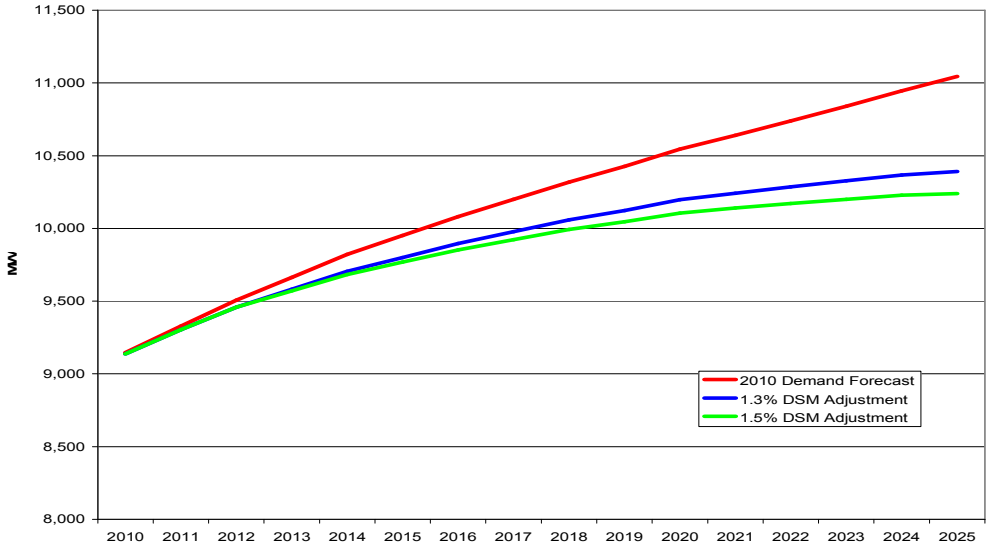
Table 3-1: DSM Goals Approved in 2010-12 CIP Triennial Plan

	2010	**2011**	**2012**	**Total**
Budget	$ 75,935,992	$ 81,002,168	$ 86,183,239	$243,121,399
Energy Savings (MWh)	349,653	367,263	399,220	1,116,136

Additional detail on our DSM programs is presented in Appendix C.

Figure 3-3 below illustrates the further reductions in demand we estimate can be achieved over time if we are able to sustain DSM savings of 1.3% and 1.5% of retail sales.

Figure 3-3: NSP Median Base Summer Peak Forecast Adjusted for 1.3% and 1.5% DSM Savings



While we are committed to working with stakeholders to expand our DSM programs to achieve the 1.5% level there remains considerable uncertainty in how to achieve these results, how quickly results can be achieved and how sustainable results will be. For planning purposes we have reduced our demand forecast to reflect the 1.3 % DSM savings level. The 1.5% level of DSM would not materially change our resource need in this case since it would reduce generation capacity requirements by only about 40 MW in the 2016 timeframe.

Our peak demand forecast includes the effects of our load management programs that have the ability to reduce peak demand by approximately 1060 MW during each year of the planning period. The need for additional resources is based on the forecast that includes the estimated effects of all DSM programs.

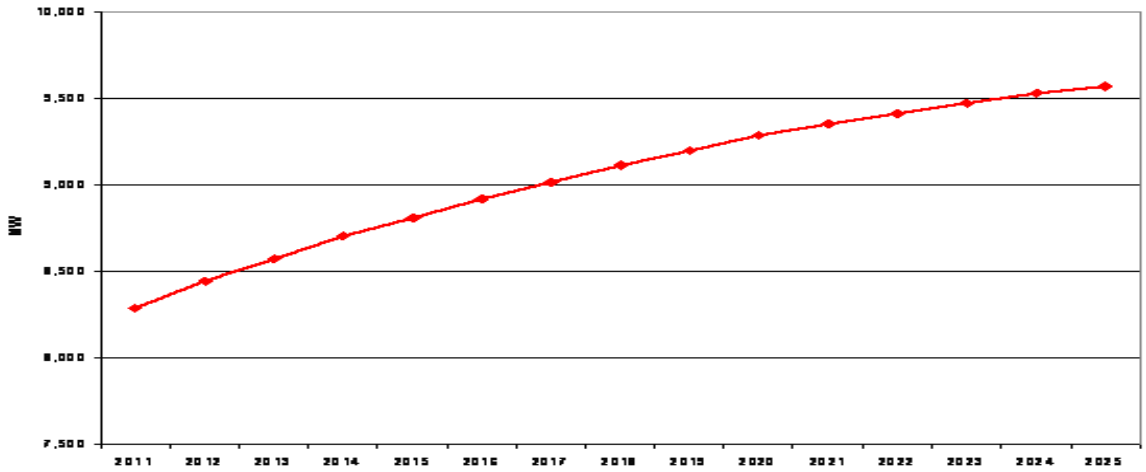
3.1.2 Reserve Requirements

The Midwest ISO establishes the Resource Adequacy Margin that each of its load-serving entities like Xcel Energy must plan for on their system to ensure adequate capacity in the region. Currently, that Reserve Adequacy Margin is 11.94% of system peak capacity. Thus, we must plan for and procure generation to meet an additional 11.94% of our system peak demand to comply with our Midwest ISO reserve requirements. Reserve margins are

reevaluated by the Midwest ISO annually. The resource need analysis described in this application uses a Reserve Adequacy Margin of 12% for the planning period.

Figure 3-4 below illustrates our peak demand forecast that includes a 1.3% DSM adjustment and 12% reserve margins. We use this adjusted forecast to assess generation resource requirements.

Figure 3-4: Medium Net Summer Peak Demand with 1.3% DSM Adjustment



3.2 Generation Requirements

We meet our customers' needs for electricity with a combination of Company-owned-and-operated generating facilities, and long- and short-term power purchases. Our most recent forecast of load requirements and available resources is illustrated below in Figure 3-5. This forecast assumes that our contracts for 850 MW of power from Manitoba Hydro are extended to 2025. Our generation resource analysis also includes 230 MW of base load capacity increases at our nuclear power plants that are underway or planned to occur during the next several years.

Figure 3-5: Requirements and Resources 2011-2024

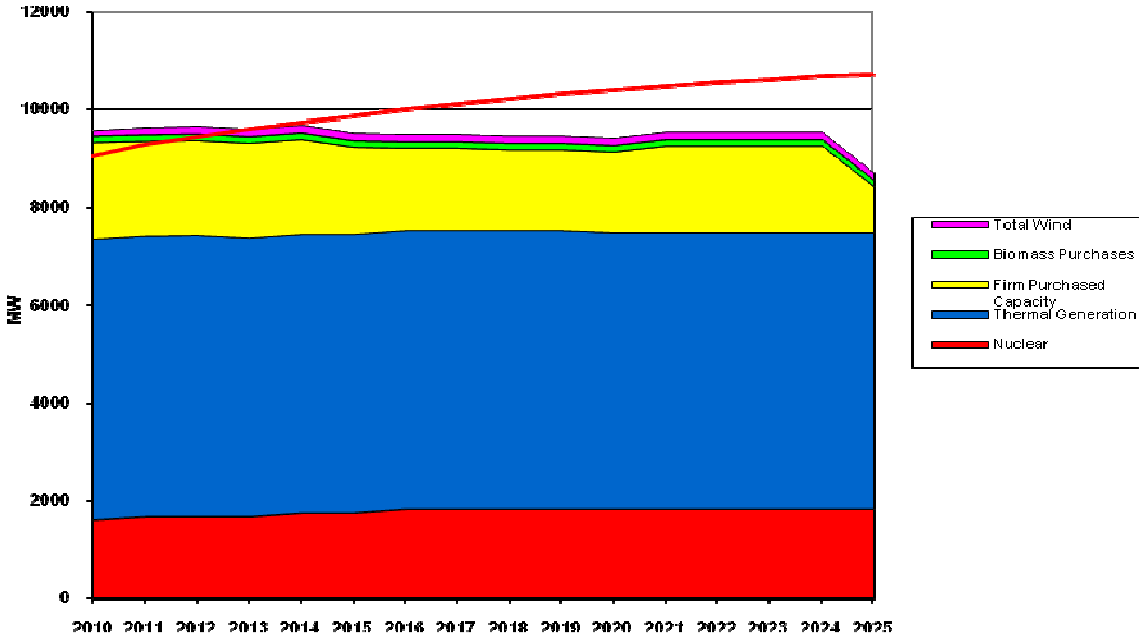
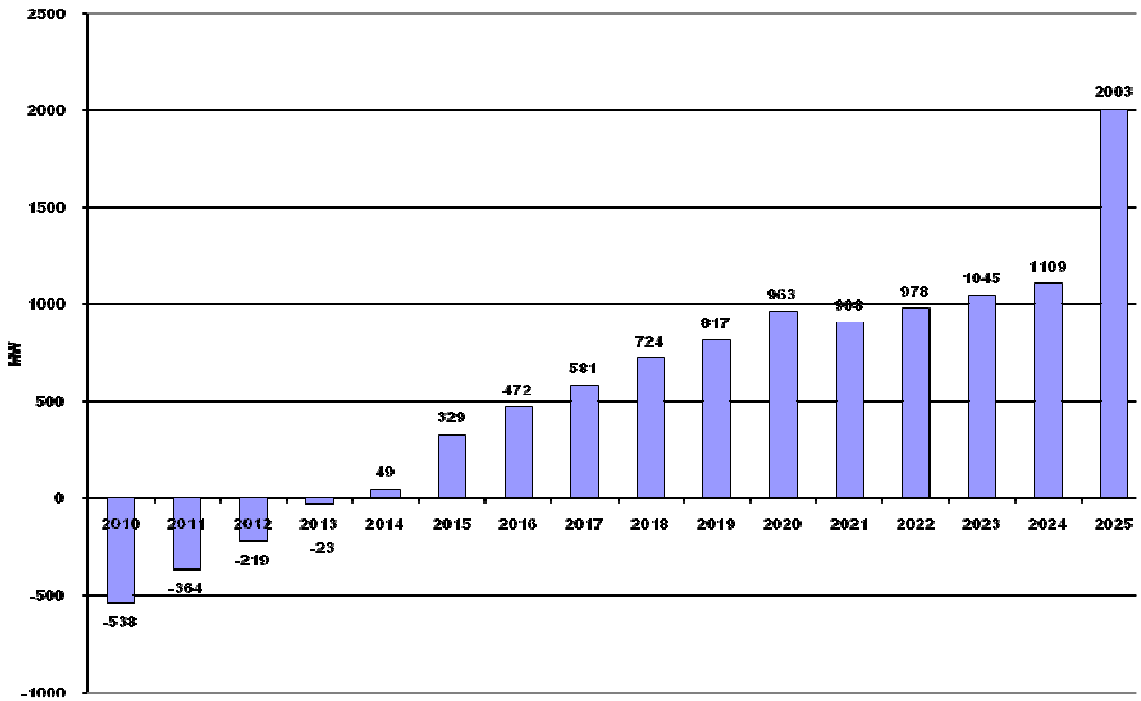


Figure 3-5 above shows that based on our forecast of customer needs, adjusted for aggressive DSM programs and Midwest ISO Resource Adequacy Requirements, we will face a significant resource capacity deficit beginning in 2015.

Figure 3-6 below shows our projected resource needs in more detail.

Figure 3-6: Forecasted Resource Needs by Year



3.3 Supply: Black Dog Units 3 and 4

Our resource assessment in Figure 3-6 assumes Black Dog Units 3 and 4 will continue to be available to generate 253 MW for another 20 years. After examining the condition and performance of the two coal fired units and the investments that will likely be necessary to keep the units operating, we have concluded our power supply will be more cost effective if we cease operating Units 3 and 4 and replace their output.

Black Dog Units 3 and 4 were put into service in 1955 and 1960. They use low sulfur, sub-bituminous coal to fuel Babcock and Wilson pulverized coal-fired boilers. Particulate matter is captured using electrostatic precipitators. The boilers, turbines and generators are essentially original equipment which has been well maintained and operated over their entire lives. However, as one would expect from 50-year-old assets, operating data shows declining availability. In order for the units to continue to operate, they will require significant investment due to aging components and systems.

If the units are to be operated another 20 years, major equipment repairs or replacements will likely be required for the turbines, generators, boiler sections, feedwater heaters, pumps and electrical equipment. The equipment would not need to be replaced all at the same time unless it became prudent to include the work as part of a larger project for cost or regulatory reasons. An investment of over $200 million in today's dollars would likely be needed over time to refurbish and/or replace aging equipment.

There are other potential risks in extending the coal-fired operation of Units 3 and 4. Many similar sized units were built during the same time period as Units 3 and 4. However, utility boilers constructed prior to Units 3 and 4 were smaller in size and most have been retired from service. This makes estimating the remaining life of high temperature and pressure components, such as steam drums, difficult due to the limited industry data and experience with similar units.

The second area of major capital investments facing Black Dog Units 3 and 4 is in the area of pollution control. The EPA is in the process of implementing major regulatory changes in air, water and waste standards. It appears these new environmental performance standards could require over $200 million in pollution control upgrades to continue to operate Black Dog Units 3 and 4.

Maintaining the status quo will not be allowed based on what we know of the expected environmental regulations summarized below.

3.3.1 Ozone NAAQS

On January 19, 2010, EPA published proposed revisions to the ozone National Ambient Air Quality Standard ("NAAQS") in the *Federal Register*. EPA's current plan is to finalize these standards in July 2011. The impact of this change depends on the numerical standard selected by EPA. The MPCA has publicly presented information on how the value selected will impact NAAQS compliance status in Minnesota and what that means to both industrial and mobile sources of NO_x emissions. Until the rule is finalized, we will not know which facilities will need what types of controls. However, the continued long-term operation of Black Dog Units 3 and 4 on coal would likely trigger a requirement for NO_x controls on theses units, including installation of a selective catalytic reduction system.

3.3.2 CAIR Caps/Proposed CAIR Replacement Rule

On August 2, 2010, the Clean Air Transport Rule ("CATR" or "Transport Rule") was proposed to replace the court-vacated Clean Air Interstate Rule ("CAIR"). Aimed primarily at the control of regional emissions to address acid rain, ground-level ozone and particulate matter precursors, the Transport Rule would set limits for states included in the rule at levels deemed necessary for the protection of downwind states' air quality. It also could allow for flexible compliance mechanisms, such as a limited form of emissions trading, similar in form to the Acid Rain Program established 20 years ago. CATR is expected to be finalized by mid-2011. Implementation dates for facilities in Minnesota would be 2012 for NO_x and 2014 for SO_2. The form and content of the final rule will dictate how this rule impacts each facility. Until the rule is finalized, we will not know which facilities will need what types of controls. However, we anticipate that Black Dog Units 3 and 4 as currently configured, would need to install NO_x and SO_2 controls, probably in the form of flue gas scrubber and bag house particulate filters, in order to comply with the rule.

3.3.3 Proposed Rule for CCBs Management

On June 21, 2010, EPA proposed rules regulating coal combustion residuals ("CCR"). The public comment period for this proposed rule ended on November 19, 2010, and EPA received a number of substantive comments concerning the various alternatives being considered. The content and timing of the final rule, which at this time remains highly uncertain, will dictate how this rule impacts Black Dog Units 3 and 4. Under one possible scenario, EPA could designate CCR's to be a "Special Waste" under the Resource Conservation and Recovery Act ("RCRA") Subtitle C, which would impose costly additional regulatory requirements for CCR handling, storage and disposal operations which might result in the need for significant upgrades to the bottom of settling ponds at the plant site.

3.3.4 CO_2 Regulation

The EPA finalized several rules regulating CO_2 in 2010. However those rules have been the subject of court challenges and Congress continues to debate the appropriateness of the Administration's approach. Due to changes in the political make-up of Congress, the possibility of further climate legislation seems less likely in the next couple of years. While legislative action is not likely to happen soon, EPA is continuing to act to regulate CO_2 from electric

utility generating units. These regulatory changes will directly impact Black Dog Units 3 and 4 if major modifications are needed to continue coal operations. If a major modification were made, we would need to conduct a Best Available Control Technology ("BACT") review for CO_2 and other GHGs and implement BACT in order to make the modification. The Repowered Plant would utilize natural gas as a fuel, effectively minimizing CO_2 emissions.

3.3.5 Hazardous Air Pollutants MACT Rule

EPA has been tasked with developing National Emission Standards for Hazardous Air Pollutants ("NESHAP") for Electric Utility Steam Generating Units ("EUSGUs"), commonly referred to as the Utility Maximum Achievable Control Technology ("MACT") rule. Under this rule EPA will be regulating a number of hazardous air pollutants ("HAPs"), including: mercury, non-mercury metallics, acid gases, dioxin/furan organics, and non-dioxin/furan organics. EPA is under a consent decree as a result of a lawsuit to issue the new standards by no later than November 2011. We anticipate that the NESHAP will require affected facilities to demonstrate compliance within 36 months thereafter. Until the rule is proposed and finalized in 2011, we do not know which facilities will need what types of controls. However, it is likely that additional controls for mercury, non-mercury metallics, acid gases, dioxin/furan organics, and non-dioxin/furan organics will need to be installed on Black Dog Units 3 and 4 as currently configured. The Repowered Plant would utilize natural gas as a fuel, effectively minimizing HAP emissions.

3.3.6 SO_2/NO_2 Primary NAAQS

On February 9, 2010, EPA finalized rules tightening the primary NAAQS for nitrogen dioxide ("NO_2"). The new standard is a one–hour standard at a level of 100 parts per billion that replaces the existing annual primary NO_2 standard. The new standard has the potential to force additional expenditures for Black Dog Units 3 and 4 to reduce emissions of NO_2.

On June 22, 2010, EPA finalized rules tightening the primary NAAQS for SO_2. The new standard is a one–hour standard at a level of 75 parts per billion that replaces both the existing 24-hour and annual primary SO_2 standards. The new standard has the potential to require additional expenditures for Black Dog Units 3 and 4 to reduce emissions of SO_2.

It should be noted that this rule will impact the Black Dog site regardless of whether the Project proceeds. The Repowered Plant would minimize NO_x emissions with control technology in order to address the NO_2 NAAQS. The Repowered Plant would utilize natural gas as a fuel, effectively minimizing SO_2 emissions.

3.3.7 SO_2/NO_2 Secondary NAAQS

EPA plans to issue a proposed rule revising the secondary NAAQS for NO_2 and SO_2 by July 2011 and a final rule by March 2012. Until EPA proposes and finalizes the rules we cannot know what will be required of the Plant to comply with the rules.

It should be noted that this rule will impact the Black Dog site regardless of whether the Project proceeds. The Repowered Plant would minimize NO_x emissions with control technology in order to address the NO_2 secondary NAAQS. The Repowered Plant would utilize natural gas as a fuel, effectively minimizing SO_2 emissions.

3.3.8 Clean Water Act 316(b) Cooling Water Intake Rule

EPA continues to develop national regulations governing the design, maintenance and operation of cooling water intake structures pursuant to Clean Water Act Section 316(b). We expect EPA to propose these rules before the end of March 2011. The draft rules are currently with the Office of Management and Budget for interagency review prior to publication. We do not know the contents of these new rules but expect that the existing Plant will be impacted by the regulations when they are promulgated. The Repowered Plant would address 316(b) requirements through the installation of a cooling tower.

3.3.9 Effluent Guidelines

On June 18, 2010, EPA forwarded an Information Collection Request ("ICR") to all coal-fired power plants and certain other plants, including nuclear. The purpose of the ICR is to collect information on waste water treatment technologies currently in use. Xcel Energy submitted our ICR responses to EPA in September 2010. EPA will now evaluate the need for changes to the effluent limit guidelines established under the Clean Water Act. The guidelines are periodically reviewed and, if warranted, changed to

reflect improved water treatment technology performance. The timing for publishing revisions to the guidelines or new rules is unknown.

It should be noted that this rule will have greater impact if Units 3 and 4 are still operating on coal versus if the entire Plant is operating on natural gas. The repowered facility will be required to comply with the effluent limit guidelines but the amount of pre-treatment required prior to discharge under the NPDES permit is expected to be less than that required for coal operations.

3.3.10 Summary of Potential Emissions Control Rule Changes

Our assessments of the possible outcomes of the entire host of rule changes underway lead us to conclude that extensive additions and changes to pollution control will be needed for Black Dog Units 3 and 4 including the following:

- modern flue gas desulfurization ("FGD") scrubbers for removal of sulfur compounds and acid gases,
- selective catalytic reduction ("SCR") reactors for removal of NO_x,
- activated carbon injection ("ACI") systems for removal of Hg and organic compounds,
- fabric filter collectors for removal of particulate matter and metallic HAPs,
- installation of a cooling tower and possibly intake screen modifications for 316(b) compliance, and
- additional process water pre-treatment of ash contact water to comply with revised effluent limit guidelines.

3.4 Conclusion: Resource Needs

In Chapter 4, we describe the analysis we have done to examine the cost impacts of the possible capital investments necessary to continue to operate Black Dog Units 3 and 4. The analysis indicates that our system will be more efficient and cost effective over the long term if we cease operating Black Dog Units 3 and 4 and replace the 253 MW of generating capacity with a new resource as part of our plan to meet growing customer needs.

It is the combined need associated with continued growth in the customer demand in the range of 470 MW and the need to replace 253 MW of aging

infrastructure that must be addressed to maintain a reliable, efficient, cost effective power supply for our customers.

3.5 Consequences of Project Delay

As shown above in Figures 3-5 and 3-6, significant resource capacity is needed on our system beginning in 2015. As we discuss in Chapter 4, the Project is the most cost effective alternative available to us, and will reduce exposure to the costs of future environmental regulations.

If this Project is delayed, we will likely need to purchase capacity and energy from short-term markets to bridge the delay. This will expose our customers to additional costs, as well as additional pricing volatility and reliability risk. If construction cannot begin in the spring of 2012, we will also see cost increases due to our estimates being dated. Obviously, the longer the Project is delayed, the greater the negative impact to our customers.

4 An Examination of Alternatives: Project is Most Reasonable and Prudent Alternative

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minn. R. 7849.0120). This section addresses the second criterion which provides that:

"a more reasonable and prudent alternative to the proposed facility has not been demonstrated by preponderance of the evidence on the record."

The Project results in a number of benefits for our customers. First, it adds about 450 MW of new capacity to our system to meet increased demand. It also replaces over 250 MW of aging resources that will otherwise require significant life extension investments and environmental upgrades in order to continue operating. The use of an existing site provides access to existing gas, transmission and other infrastructure that will result in reduced costs and enhanced reliability for our customers. The flexibility of the natural gas combined cycle technology will allow us to better integrate wind resources with dispatchable power supplies. Finally, the Project provides a significant hedge against future environmental costs and regulations. As a result, the Project is more reliable, more economic and more environmentally acceptable than other alternatives.

4.1 Alternative Evaluation Criteria and Project Objectives

To evaluate the reasonableness of the Project, we compared the Project to alternatives using multiple criteria. The results of this comparison demonstrate that the Project is the best alternative to meet the need identified in our 2010 Resource Plan.

The criteria considered in the development of the Project objectives and for evaluation of Project alternatives include the following:

- Cost

  Cost is an important factor in determining the reasonableness of any proposal. The Project has the lowest total system costs of the alternatives considered. In addition, the costs for the Project are more certain and involve less risk than other alternatives.

- Reliability

  It is critical that any generation resource we add to our system enables us to continue to provide our customers with reliable electric service. The existing Plant has a good reliability record, and our proposed Project in the same location will continue that record. In addition, the location within the metropolitan area provides additional reliability benefits. The transmission system that serves the metropolitan area around the Twin Cities has grown up around the Plant. Generation at this site supports the transmission grid for the entire metropolitan area.

- Environmental Impacts

  As we described in Chapter 3, we are in a period of unprecedented regulatory flux regarding continued operation of these coal fired units. In order to mitigate the risk posed by these potential environmental regulations, we have been working to reduce environmental impacts on our system. This Project will continue that trend by replacing 253 MW of coal generation with about 700 MW of efficient natural gas-fired generation resulting in lower emissions and lower risk for our customers.

- Appropriateness

  The Project results in meeting the appropriate size, type and timing of our resource need. We have system needs of 472 MW in 2016 (as shown in Figure 3-6), of which the Project can satisfy about 450 MW (the rest can be easily obtained through short-term capacity purchases). In addition, the Project will be able to operate in a flexible intermediate service mode that will allow us to better integrate the high level of wind resources on our system. Finally, the Project can be completed by January 1, 2016, in time to meet our customers' needs.

These criteria can be further explored in this proceeding as needed.

4.2 Alternatives Evaluation Approach

Minnesota Statutes Section 216B.243 and Minnesota Rule 7849.0250 set out a number of alternatives that must be discussed when considering the construction of a Large Energy Facility. Based on this direction, we have evaluated the following options as potential alternatives to the Project:

- Increased Efficiency of Existing Facilities, including transmission lines
- Purchased Power
- New Transmission Lines
- New generating facilities of a different size or type
- Increased Efficiency and DSM Efforts
- Distributed Generation
- Renewable Energy

Our evaluation of alternatives followed a multi-step process. First, we performed a qualitative screening to identify alternatives that have similar energy and capacity characteristics to the Project. Alternatives that were not reasonably applicable to the need or that were deemed to be excessively risky or costly were screened from further consideration. We then modeled the remaining alternatives in Strategist, comparing the system costs and environmental emissions from these options to those of the Project. Our findings confirm that the Project is the most cost effective project to implement at this time.

4.3 Qualitative Screening of Alternatives

4.3.1 Increased Efficiency of Existing Facilities

This Project continues our efforts to increase the efficiency of our generation fleet. Over the past several years, the Company has identified and implemented a number of efficiency upgrade projects. Our King, Riverside, and High Bridge facilities, which were all part of our Metropolitan Emission Reduction Program ("MERP"), were upgraded to increase efficiency and generation capacity. In addition, we are pursuing uprate/upgrade projects for our Prairie Island, Monticello and Sherco 3 generating units. Our aggressive pursuit of efficiency upgrades leaves few additional opportunities beyond this Project. For this reason, increased efficiencies at existing plants are not feasible to satisfy the intended need and we did not do further analysis.

4.3.2 Long-Term PPAs

Long-term PPAs are an important part of our resource mix. While we have not identified specific long-term PPAs that could potentially fill the need required by the Project, it is possible that competing proposals may be offered in this proceeding in the form of PPAs from independent power producers/developers. As part of this Certificate of Need process, it is expected that developers will be able to offer and advocate for competing proposals.

For an alternative to be considered, the developer must submit the alternative as part of this proceeding and include all information necessary to evaluate the alternative against the Company's Project. If a developer successfully demonstrates its alternative is superior, the Commission can direct the Company to negotiate a PPA with the developer instead of pursuing the Project. This process helps ensure the best value resource is selected.

Depending on the nature of the competing proposal, the PPA may have to be treated as a lease, either an "operating lease" or as a "capital lease" by Xcel Energy. Accounting guidance currently requires capital leases to be treated as long-term debt with a corresponding asset on the Company's balance sheet. Therefore, a PPA that must be treated as a capital lease can have a significant impact on the Company's capital structure. The result would likely be a higher debt to equity ratio and an impact to the cost of capital. Additionally, the impact to Generally Accepted Accounting Principles ("GAAP") recognized expenses resulting from accounting for either an operating lease or a capital lease may be different than the timing of cost recovery currently allowed which would make it necessary to seek to align our GAAP expense recognition with the allowed regulated cost of service to avoid material income statement impacts.

As part of the consideration in determining whether a specific PPA is a lease for financial reporting purposes, preparers and auditors look to the rights conveyed in an agreement from the owner of the assets to the party contracting to use the assets. If a purchase is determined to be a lease, the analysis turns to classifying the lease as an operating lease or a capital lease. In general, the more control and more risk conveyed to the purchaser, the

more likely that the agreement will be considered a lease. Current accounting guidance under Accounting Standards Codification ("ASC") 840 requires that the facts and circumstance surrounding the transaction be reviewed to determine if lease treatment is applicable. Additionally, there are new proposed accounting rules that might require all leases to be recognized in a manner similarly to the capital lease treatment. These rules have been proposed by the Financial Accounting Standards Board ("FASB") in an Exposure Draft which may be finalized during 2011. Evaluating PPAs from a technical perspective is complex and can be challenging especially when key relevant facts are not available for consideration prior to negotiation of a written PPA.

In the case of a capital lease, the Company's balance sheet would have to show the capital lease as a fixed asset and an associated obligation that would be treated as long term debt. By recognizing a capital lease as a long term liability on the Company's balance sheet, the long term debt ratio in our capital structure increases adding the potential that equity infusions would be necessary to maintain the same economic capital structure. As previously mentioned, the timing and level of expense recognition associated with a lease will likely differ from the actual lease payments. Cost recovery should consider the higher expenses in the earlier years to reflect such a power purchase.

We identify these issues in this application to ensure that the Commission and interested parties are aware of the accounting issues and the impact they could have on customer rates. This impact will need to be incorporated into the evaluation of any PPA alternative in order to fairly compare it to the Project. If a competing PPA is offered, we look forward to working with parties toward this end.

4.3.3 Short-Term Purchased Power

Short-term purchases provide for flexibility in our resource portfolio. We typically acquire short-term power to meet unexpected increases in our load and to optimize the timing and cost of adding long-term resources. The price for short term resources varies with the market and can only be fixed for short periods of time. In addition, contracts for short term capacity do not always guarantee that energy will be delivered when it is needed.

Using short-term contracts to serve a substantial part of our long-term resource need would expose our customers to unacceptable levels of cost risk. In order to balance the benefits and risks of using short-term resources in our portfolio we work to limit our dependence on short-term purchases to something on the order of 300 MW annually. While we have some concerns about firm transmission service for these purchases, we believe this level of short-term power purchases provides the best level of benefits to our customers.

The resource need addressed by the Project is significantly greater than 300 MW. Thus, our assessment is that it would be too risky to rely on the short-term market to satisfy this resource need. Short-term purchases are not a prudent resource option to meet the long term need met by the Project.

4.3.4 New Transmission Lines

While additions to the electric transmission system could potentially provide access to additional generation resources to satisfy our resource need, new transmission is not a viable alternative for this Project. The underlying assumption with this alternative is that additional transmission infrastructure would provide access to new or existing capacity resources. We are currently unaware of additional generation resources that, with the construction of new transmission, could cost effectively provide our customers with the needed energy and capacity. Timing is also an issue when considering transmission as a viable alternative. Transmission capacity of any size can take several years to plan, permit, site and construct and would likely not be available in time to meet the customer need.

4.3.5 New Generating Facilities of a Different Size or Type

We considered a number of other potential generation projects. Most of those were discarded as not viable, at least within the timeframe when the resource is needed. Among a number of other issues, new nuclear, coal or hydro facilities cannot be constructed by 2016. Based on our screening of new generation facilities, however, we selected two major alternatives for further evaluation. The first would be to upgrade the existing Units 3 and 4 to allow for continued operation of these units and add additional new natural gas generation to meet the balance of the needed resources. The second option would be to construct new natural gas-fired generation at various sites to meet the full need, including the capacity currently provided by the existing

Units 3 and 4. As discussed below, to meet our requirements with respect to renewable energy sources, we also included a biomass generation alternative in our quantitative analysis.

4.3.6 Demand-Side Management

Our DSM programs are presented in more detail in Appendix C. Over the last few years, we have approximately doubled the amount of DSM we plan to obtain and as discussed in our 2010 Resource Plan, we have committed to achieving a 1.15% reduction in sales from DSM in 2010, 1.2% in 2011 and 1.3% in 2012 and continuing to ramp up to the statutory savings goal of 1.5%.

Meeting these goals each and every year will be very challenging. We will continue to launch new programs as well as expand existing programs in our efforts to attempt to meet the targets. We believe this aggressive expansion of DSM programs pushes the limits of achievable potential in our service territory and creates significant uncertainty regarding the size and timing of actual savings. As a result, it is unreasonably risky to rely on even more DSM in order to replace the energy and capacity from this Project. If DSM were to be selected as an alternative to the Project and the Company failed to achieve the necessary savings, we would be forced to buy replacement capacity and energy from the market, to the extent accessible, exposing our customers to higher costs, greater volatility and reduced reliability.

Therefore, the Company concluded that additional DSM saving beyond our current targets is not a feasible alternative.

4.3.7 Distributed Generation

Pursuant to Minnesota Statutes Section 216B.2426, we also considered the use of distributed generation to meet the need. In Minnesota, distributed generation ("DG") is defined generally as generation that is located on or near the site where the output is primarily to be used, interconnected to and operated in parallel with the electric grid, with a total capacity of no more than 10 MW.[3]

---

[3] In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212, Docket No. E-999/CI-01-1023, ORDER ESTABLISHING STANDARDS (September 28, 2004). Minnesota defines renewable projects between 10 and 40 megawatts as "dispersed" renewable generation (DRG). See Laws of Minnesota 2007, chapter 136, article 4, section 17.

Additionally, the capacity of the DG installation must be lower than the minimum load of the distribution system to which it would be interconnected, so that the energy generated by the DG facility is used locally.[4]

As discussed in Chapter 8 of our 2010 Resource Plan, we have undertaken a number of programs to promote the development of distributed generation on our system, and will continue to pursue and promote these technologies. However, we are not aware of available distributed generation resources in the quantities that would be necessary to replace about 700 MW that would be provided by the Project. In addition, based on available cost estimates for distributed generation resources, these resources would not be cost-effective. We therefore excluded this option from further consideration.

4.3.8 Renewable Energy Alternatives

There are four statutes that require the Company to look at various renewable energy options. The options we are required to address are: Community-Based Energy Development ("C-BED"), the impact of the Project on the Company's ability to meet the Renewable Energy Standard ("RES"), the availability of innovative energy alternatives and if there is a renewable resource that can meet our needs. We discuss each of these options below.

C-BED

Minnesota Statutes Section 216B.1612, subdivision 5 requires the Company to "take reasonable steps to determine if one or more C-BED projects are available that meet the utility's cost and reliability requirements." We do not believe there are one or more C-BED projects available that would meet our needs. As discussed in Chapter 2 of this application, we are filing this application as a Track Two process. Thus, if there are any C-BED projects that believe they could meet the need required, we welcome their participation in this process. However, because we have conducted a number of RFPs to obtain C-BED proposals and continue to see C-BED projects miss in-service date requirements, we do not believe this is an option that could fulfill this need. Additionally, we have a need for a resource that can fill in the gaps when renewable energy projects are either not producing or are ramping up or down in their production. Thus, adding additional renewable

[4] See "Potential for and Barriers to State Jurisdiction Over Interconnecting Dispersed Generation Projects," Minnesota Office of Energy Security, June 6, 2008; and Phase II Report of the Technical Standards Workgroup Regarding Distributed Generation, MPUC Docket No. E999/CI-01-1023, Attachment 1, page 1.

energy that is variable in its production timing and availability will not fill the gap that is needed at this time.

RES

Minnesota Statutes Section 216B.243, subdivision 3(10) states that the Commission shall evaluate whether the applicant is in compliance with the applicable provisions of Minnesota Statutes Section 216B.1691 (the RES statue) and 216B.2425, subdivision 7. The RES requires the Company to obtain renewable resources such that 30 percent of retail electric sales are met by renewables by 2025. The Commission issued a letter on July 8, 2010 in Docket No. E999-PR-10-267 confirming that the Company was in compliance with the RES for 2009. Our compliance filing for 2010 is due on June 1, 2011. We will report compliance for 2010 in that filing. The Black Dog Repowering Project will not interfere with our ability to meet the RES requirements. If anything, this Project will help us better incorporate renewable resources because of their variable generation patterns.

Innovative Energy Alternatives

Minnesota Statutes Section 216B.1694 requires consideration of an innovative energy alternative as a supply option. There is no Innovative Energy Project currently being proposed. Thus we believe this Statute and its companion Clean Energy Technology Statute (Minn. Stat. § 216B.1693) do not limit this application. Nevertheless, as discussed in Chapter 2 of this application, we are filing this application as a Track Two process. Thus, if there are any innovative energy alternative projects available that could meet the need required, we welcome their participation in this process.

Meeting Need with Renewable Resource

Minnesota Statutes Section 216B.243, subdivision 3a requires the Company to evaluate renewable resources and show that the renewable resource is more expensive than the alternative selected. For this analysis, we have selected a biomass-powered facility as the best option available to us to meet the capacity and energy need in 2016. We selected this alternative to be modeled in the quantitative phase of the alternative analysis, despite significant concerns about the availability of adequate biomass resources, the potential costs of such resources and whether 700 MW of biomass generation could be permitted and constructed in time to meet the need.

4.3.9 No Facility

Minnesota Rule 7849.0340 also requires the Company to evaluate whether or not the alternative of no facility would be available to meet the needs of our customers. If the Project were not to be undertaken, we would experience a deficit starting in 2015. This deficit will grow to about 2,000 MW by 2024. Due to our requirement to provide safe, adequate and reasonable electric service pursuant to Minnesota Statutes Section 216B.04, "no facility" is not an option as we would experience a deficit in 2015 and beyond if the Project or an alternative is not undertaken.

4.4 Economic and Environmental Analysis

Based on the discussion in Section 4.3 above, we selected four alternatives for quantitative comparison using the Strategist model. These alternatives are:

- Life Extension

  Investing in the life extension and environmental control retrofits necessary to continue to operate Units 3 and 4 on coal while fulfilling the remaining need with new generation facilities;

- Repowering Project

  Cease operation of Units 3 and 4 and construct about 700 MW of combined cycle generation at the Black Dog Generating Plant site;

- Alternative Generation Model

  Cease operation of Units 3 and 4 and add necessary resources elsewhere on the NSP system to fulfill about 700 MW of need; and

- Biomass Alternative

  Cease Operation of Units 3 and 4 and fulfill the need with about 700 MW of biomass-fueled generation.

4.4.1 Strategist Modeling Tool

We use the Strategist resource expansion model[5] to analyze the impacts of various long-range electric supply and demand alternatives on our system. Strategist:

- Develops and ranks resource expansion plans that can meet our needs, given the input assumptions.
- Calculates the Present Value of Revenue Requirements ("PVRR") to measure the economic impacts of various planning scenarios.
- Calculates environmental impacts of the plan, using forecasted emission rates and externality values as applicable.

Strategist is useful as a planning tool in two ways. First, given a set of assumptions about the forecasted demand for electricity and the resources available to meet that demand, Strategist will optimize the operation of existing resources and add new resources to develop the expansion plan with the lowest PVRR possible.

We also use Strategist as a tool to determine the PVRRs of alternative cases. In this case, we insert a particular resource or an entire expansion plan into the model and the resulting PVRRs can be compared to other options to analyze the effects of different resource choices.

The Strategist model has some limitations. It is not a chronological dispatch model; that is, it does not simulate the operation of the system from hour to hour. The model is not able to simulate the ramp rate of units and other order-dependent variables that may affect the operation of the system. Instead, Strategist simulates system dispatch for each hour independently of what occurs before or after that hour. Overall, we have found Strategist to be a valuable tool for evaluating the impacts of long-term resource choices.

We have used the Strategist model to perform analyses presented in all of our Resource Plans since 2000, and in multiple other dockets since that time, including:

- Certificate of Need for the Blue Lake Generating Plant Expansion Project (Docket No. E002/CN-04-76);

[5] "Strategist" is a registered trademark of Ventyx. Ventyx developed and maintains the Strategist model.

- Certificates of Need for the Monticello Nuclear Generating Plant, to Establish an Independent Spent Fuel Storage Installation (Docket No. E-002/CN-05-123) and for Extended Power Uprate (Docket No. E002/CN-08-185;

- Certificates of Need for the Prairie Island Nuclear Generating Plant, for Extended Power Uprate (Docket No. E002/CN-08-509) and Additional Dry Cask Storage (Docket No. E002/CN-08-5100; and

- Petition for Approval of Power Purchase and Diversity Exchange Agreements with Manitoba Hydro (Docket No. E002/M-10-633).

4.4.2 Base Case Assumptions and Load Forecasts

The Strategist inputs used in this analysis are based on the assumptions used in the Company's 2010 Resource Plan. In order to ensure that the Commission has the best information available to make its decision, we have updated or refreshed the cost estimates for various resources as well as our fuel price forecasts and other assumptions.

We model our entire generation fleet in Strategist. Inputs for each unit include: maximum dependable capacity, firm capacity, heat rate profiles, emission profiles, maintenance schedules, forced outage rates, fuel cost, variable O&M, and fixed O&M.

Wind resources are modeled using representative hourly generation profiles. The nameplate capacity is multiplied by the hourly profile to estimate the units' generation. This enables Strategist to simulate the variability of wind and to predict the dispatch of thermal units needed to support these resources. Biomass plants are modeled much like other thermal plants and are dispatched on economic merit. Hydropower is modeled either as run-of-river where energy is provided at a constant rate, or as a dispatchable resource for hydro resources with pooling capabilities.

4.4.3 Black Dog Generating Plant Life Extension

Under this alternative, the 253 MW (2010 summer rating) of existing coal-fired generation at Black Dog Generating Plant Units 3 and 4 would be retrofitted to allow for 20 years of additional continued operation. This would require major equipment repairs or replacements for the turbines, generators, environmental control, boiler sections, feedwater heaters, pumps and electrical equipment. The equipment would not all be replaced at the

same time unless it became prudent to include the work as part of a larger project for cost or regulatory reasons. However, we estimate that an investment of over $200 million in today's dollars would likely be needed to replace aging equipment.

The cost of complying with pending environmental regulations would also require new investments. For planning purposes we assumed that the EPA's Hazardous Air Pollutants MACT Rule will take effect by the end of 2014, although limits and implementation dates have not been set to date. In order to achieve high levels of HAPs reduction we envision the rule will require, a combination of ACI and a fabric filter dust collector would be needed. In order to be able to continue coal operations for an additional 20 years, emissions of SO_2 and NO_x would be reduced through the addition of a flue gas scrubber and SCR technology. Based on current information, the environmental investments would be in excess of $200 million needed in addition to the $200 million to replace aging equipment in today's dollars.

Because the capacity need in 2016 is greater than what would be provided by Units 3 and 4 in this scenario, Strategist selected two simple cycle combustion turbine units to be installed in 2016 to supplement the extended operations of Black Dog Units 3 and 4.

4.4.4 Black Dog Repowering Project

As part of this Project, we will discontinue coal operations at Units 3 and 4 in 2013, but the Units will still be available to generate using natural gas as a boiler fuel. While for economic reasons the Units would be unlikely to dispatch as often on natural gas as they did on coal, switching to natural gas will allow the current capacity to remain available throughout the construction period, and continue to generate energy when it is needed. About 700 MWs of combined cycle generation will be constructed in the area reclaimed from the existing coal storage yard and will be in commercial operation by January 2016.

The combined cycle facility is based on "F" class combustion turbines, heat recovery steam generators with supplemental duct firing for additional peak generation capability, and a single condensing steam turbine. Facility cooling will utilize the cooling water currently allocated to the existing Plant. The combustion turbines will be fueled by natural gas. The output will be stepped up to 345 kV at a new substation and transported over a short distance of

new 345 kV lines to the existing 345 kV transmission lines which run through the Black Dog Generating Plant site property.

4.4.5 Alternative Generation Option

Under this scenario, we ceased operating Units 3 and 4 at the end of 2014. We allowed Strategist to select new generic resources to replace the output of these units and to meet any additional resource needs. Strategist selected three combustion turbines to be installed between 2015 and 2017 to satisfy the capacity need for this period, including the retirement of Black Dog Units 3 and 4.

4.4.6 Biomass Alternative

Under this alternative, 700 MW of biomass-fueled generation would be added in 2015 and 2016. We used available engineering data to estimate the cost of these units. As shown in Table 4-1 below, the Biomass Alternative was approximately $2.5 billion more expensive on a PVRR basis than its closest alternative.

Notwithstanding the cost of a biomass option, it is unlikely that we would be able to procure sufficient biomass to fuel this amount of capacity. The availability of biomass as a fuel for generation has been a technical and economic challenge for much smaller generation projects than those contemplated under this option, and has been a very contentious issue relative to alternative uses of biomass.

4.4.7 Modeling Results

Our Strategist results indicate that the Black Dog Repowering Project alternative is the most cost effective option we evaluated and is on a PVRR basis $146 million less than the Alternative Generation Option (its closest competitor). This cost differential is primarily due to the Project benefits that include re-using an existing site, water systems and other facilities. Further, this PVRR difference does not capture other benefits such as use of existing transmission capacity, which are not modeled as part of generic units in Strategist.

The Black Dog Repowering Project PVRR is also about $485 million lower than the Black Dog Generating Plant Life Extension alternative (see Table 4-1 below).

Table 4-1: Cost Comparison of the Strategist System Expansion Plan with the Black Dog Repowering Project as Compared to Plans with Alternatives ($000s)

	PVRR	Difference from BD Repowering
Black Dog Repowering Project	$99,940,255	---
Alternative Generation	$100,086,164	$145,908
Black Dog Life Extension	$100,425,262	$485,007
Biomass Alternative	$102,944,542	$3,004,287

We also compared the Black Dog Repowering Project against the Alternative Generation and Life Extension options across a range of sensitivities. As shown below in Table 4-2, the PVRR's of the Black Dog Repowering Project are much lower than those of the other options across all sensitivities.

Table 4-2: Cost Sensitivity Analysis – PVRR Comparison

	Plan with Black Dog Repowering Project ($000)	Alternative Generation Diff from Plan ($000)	BD Life Ext Diff from Plan ($000)
Base ($0 CO_2)	$99,940,255	$145,908	$485,007
High Gas (+20%)	$101,310,664	$160,236	$346,408
Low Gas (-20%)	$98,559,307	$126,683	$617,448
High Load (80th Percentile	$105,222,853	$181,340	$509,419
Low Load (20th Percentile)	$96,401,192	$51,512	$392,089
High CO_2 ($34/2012)	$110,865,165	$216,190	$977,875
Mid CO_2($17/2012)	$105,403,747	$171,709	$721,338
Low CO_2($9/2012)	$102,826,842	$161,287	$609,578
Very High Capital Expenditures(+20%)	$100,074,311	$11,853	$350,952

	Plan with Black Dog Repowering Project ($000)	Alternative Generation Diff from Plan ($000)	BD Life Ext Diff from Plan ($000)
High Capital Expenditures(+10%)	$100,007,283	$78,880	$417,979
Low Capital Expenditures(-10%)	$99,873,228	$212,936	$552,035
No MISO Market	$99,991,181	$175,762	$484,403
High Externalities	$100,276,105	$142,517	$517,172
Low Externalities	$100,069,066	$143,490	$507,332

We also reviewed the differences in the fuel mix for the life extension versus the Black Dog Repowering Project as there has been a concern in the past that by adding more natural gas units we would be disproportionally expanding the amount of gas used on the system. As shown in the figures below, this is not the case.

Figure 4-1: Fuel Use with

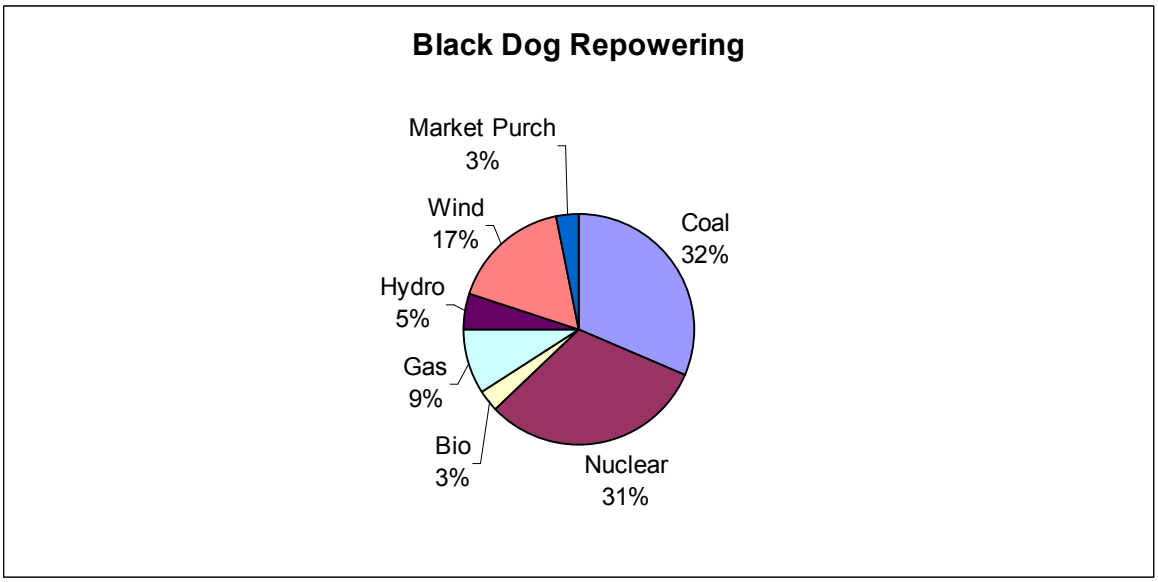
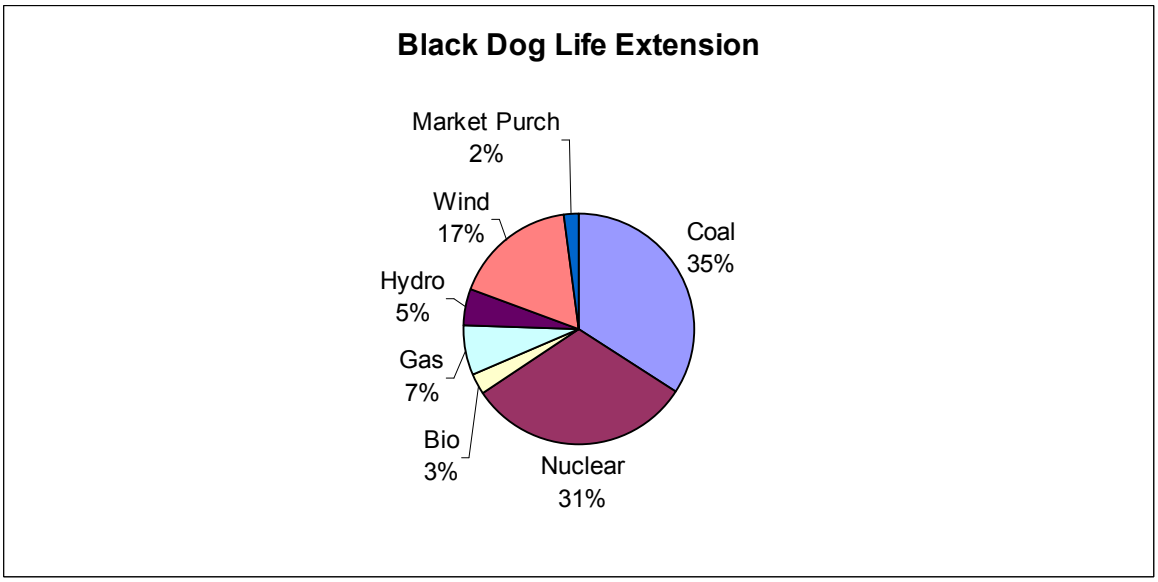


Figure 4-2: Fuel Use with



4.4.8 Cooling Tower Sensitivity

As part of the Project base costs, we include $22 million for a cooling tower. This is the incremental portion of the full cost of a cooling tower that would be assigned to the Project. We also tested a scenario where the entire cost of a cooling tower would be allocated to the Project. This case could arise in the event that it is conservatively assumed that a cooling tower would not be required for Unit 5/2 absent the Project. The entire cost of a cooling tower

would be approximately $70 million. Our analysis of this sensitivity is shown in Table 4-3 below which demonstrates that except under extreme circumstances, the Project would continue to be more cost-effective than the other options.

Table 4-3: Cooling Tower Sensitivity
PVRR Comparison of Project to Alternatives

	Black Dog Repowering Project ($000)	Alternative Generation Diff from Project ($000)	Life Ext Diff from Project ($000)
Base Case ($0 CO_2)	$99,994,913	$91,251	$430,350
High Gas (+20%)	$101,365,322	$105,579	$291,751
Low Gas (-20%)	$98,613,964	$72,026	$562,791
High Load (80th Percentile)	$105,277,510	$126,682	$454,761
Low Load (20th Percentile)	$96,455,849	($3,145)	$337,431
High CO_2 ($34/2012)	$110,919,822	$161,533	$923,218
Mid CO_2 ($17/2012)	$105,458,404	$117,052	$666,681
Low CO_2 ($9/2012)	$102,881,500	$106,630	$554,921
Very High Capital Expenditures (+20%)	$100,128,968	($42,804)	$296,294
High Capital Expenditures (+10%)	$100,061,940	$24,223	$363,322
Low Capital Expenditures (-10%)	$99,927,885	$158,279	$497,377
No MISO Market	$100,045,838	$121,104	$429,746

	Black Dog Repowering Project ($000)	Alternative Generation Diff from Project ($000)	Life Ext Diff from Project ($000)
High Externalities	$100,330,762	$87,860	$462,514
Low Externalities	$100,123,724	$88,832	$452,674

4.4.9 Delay Scenario

The timing of the investments in the life extension scenario depend in part on the implementation dates of the Hazardous Air Pollutants MACT Rule, with compliance dates currently expected to be 2014. To examine the effect of a delay in those requirements, we also evaluated a scenario where we pushed out the implementation of the Black Dog Repowering Project until 2018. Under this scenario, we would discontinue coal operations in 2015 and construct the combined cycle to be in service by January 1, 2018.

The delay scenario did not show that there would be any benefits to delaying the implementation of the Black Dog Repowering Project to 2018, even if compliance date for the Hazardous Air Pollutants MACT Rule was delayed for two years. This is because the Company still requires new capacity in 2016 to meet customer demand, and the delay of the Project would necessitate the implementation of at least two combustion turbines in 2016. The result of the delay would be a swap between the Black Dog Repowering Project and Combustion Turbines that currently show up as additions in our 2010 Resource Plan in 2018 and 2019.

4.4.10 Emissions

Table 4-4 below shows the system emissions are significantly lower with the Project than the system emissions assuming the alternative scenarios for a number of critical types of emissions. Given the abundance of federal emissions regulations that are pending over the next few years as discussed in Chapter 3, reducing our emissions increases our ability to meet compliance requirements and reduces the operational challenges associated with providing service to customers while at the same time implementing compliance programs. It should be noted that our estimates of system

emissions did not attempt to account for emission reductions that may be necessary at other plants on our system as time passes. Actual system emissions under each scenario will probably be lower but the comparisons are still valid.

Table 4-4: Emissions Differences between the Black Dog Repowering Project and the Alternatives (Total System Tons Emitted 2010-2049)

	Black Dog Repowering System Total	Alternative Generation	Black Dog Life Extension
		Diff from Repowering (+/-)	
SO_2	1,094,300	+ 27,136	-2,128
NO_x	753,436	+ 17,370	+3,851
CO_2	948,195,698	+ 5,296,874	+ 36,391,168
CO	129,064	+ 3,660	+ 9,335
PM10	109,084	+ 211	+ 7,000
VOCs	20,535	- 1,312	- 647
Mercury	15.4	+ 0	+ 1

4.5 Alternatives Evaluation: Project is the Best Option

Based on the alternatives that were considered above, the Project is the best option to meet our resource needs beginning in 2016. In addition to meeting the capacity requirements, the Project reduces potential cost by using highly efficient combined cycle combustion turbine technology at an existing site with access to existing natural gas and transmission infrastructure. It improves both the flexibility of our generating fleet and the environmental profile of our system. On a life-cycle basis, the Project cost is estimated to be substantially lower than options that propose new generation elsewhere on our system.

4.5.1 Best for Service Need

The Project is the best option for addressing the need for more flexible resources on our system. As our wind portfolio continues to grow, our greatest need is for resources that can adjust load quickly to meet unserved demand as the wind waxes and wanes. The combined cycle technology is well-suited to meet our load-following objectives because of its ability to be brought into service quickly and operate efficiently at a range of outputs for variable durations. The coal-fired life extension option and simple cycle technology-based generation that could otherwise be used to meet our needs cannot be operated as cleanly, efficiently and economically as this combined cycle Project.

4.5.2 Best for System Reliability

The Project is the best option for enhancing the reliability of the bulk electric system. Locating the Project at an existing site within the metropolitan Twin Cities' transmission beltway furthers system reliability because the resource is close to the load, thereby reducing strain on an already taxed regional transmission system and system losses. Additional reliability is provided through use of the combined cycle technology which is among the most reliable generation technologies. The Project will include firm gas supply contracts to address fuel reliability without the need for a backup fuel oil supply.

4.5.3 Best for Environment

This Project also provides the lowest environmental impacts of the options studied. This Project allows the Company to leverage existing generation infrastructure while at the same time employing proven, efficient and environmentally-friendly technology. The air emissions are significantly lower than the existing coal-fired units as well as the other alternatives studied. All other options studied would likely result in the need for new greenfield sites to construct new simple cycle generation and transmission lines elsewhere. Retiring Black Dog Units 3 and 4 presents an important opportunity and moment in time to modernize our generating fleet and take advantage of a unique location and the infrastructure that has developed there over the years. If the site is not redeveloped now we may loose the chance to realize the site's benefits in the future as land use patterns change.

4.5.4 Most Cost Effective

The Project is the best option to enhance customer value and reduce risk by leveraging existing generation, transmission and natural gas pipeline capacity contracts and renewing aging facilities. The economic analysis developed in the Strategist modeling indicates the Project has the lowest total system cost of the available alternatives under nearly every scenario considered. In addition, the costs for the Project are more certain and involve less risk than other alternatives. The Project further protects Xcel Energy customers from short-term energy price volatility and provides a hedge against the cost of future environmental regulations.

4.6 Rate Impact

The rate impact differences between the alternatives are relatively small, especially over time, but the Project has the lowest rate impact over the next 10 years as shown in Table 4-5 below.

Table 4-5: Percent Increase in Rates for the Black Dog Repowering Project and Alternatives

Rate Impacts over Time	Percent increase in rates for each alternative over the selected time frame		
	2010-2020	2010-2030	2010-2049
BD Repowering Project	2.98%	2.78%	1.60%
Alternative Generation Option	3.01%	2.78%	1.61%
Black Dog Life Extension	3.07%	2.79%	1.62%

We are also required to provide a first year rate impact of the Project. The effect of this Project in 2016 would increase customer prices by $0.002221 per kWh. We believe that the price increase when combined with the flexibility, reliability and environmental benefits provides a reasonable impact to customers. Furthermore, there is no more reasonable and prudent alternative to the Project.

5 Project Description

This chapter provides a description of the existing Black Dog Generating Plant, the changes necessary to repower Units 3 and 4, the new 345 kV substation, modifications to a section of existing lines and the new 345 kV transmission lines that will encompass the entire Project. Table 5-1 contains the operational information on the existing units as required in the Commission's application content rules, Minnesota Rule 7849.0250(A), Minnesota Rule 7849.0320(C) and Minnesota Rule 7849.0320(E).

5.1 Existing Plant Information

The Black Dog Generating Plant is a coal- and gas-fired generating station, located on the Minnesota River just south of the Twin Cities.

The original Unit 1 boiler/turbine and the Unit 2 boiler, installed in the 1950s and fired on coal, were repowered with a natural gas combined-cycle unit (Unit 5), which includes a natural gas combustion turbine-generator combined with a HRSG. Exhaust heat from Unit 5 powers the Unit 2 steam turbine. The repowering project, completed in summer 2002, increased output from the two original units by more than 100 MW, and resulted in greater operating efficiency and cleaner power production.

Black Dog Units 3 and 4 were put into service in 1955 and 1960, respectively. Units 3 and 4 are dual-fuel boilers with steam turbines that utilize coal as the primary fuel. Natural gas is the backup fuel that can be used to obtain maximum generation from both units. The boilers, turbines and generators are essentially original equipment which have been well maintained and operated over their entire lives. However, operating data shows a declining availability as the units continue to age. They were originally designed for a 35 year life and have recently exceeded 50 years of operation. At the proposed time of retirement in 2016, Unit 3 will have operated for 60 years and Unit 4 for 55 years.

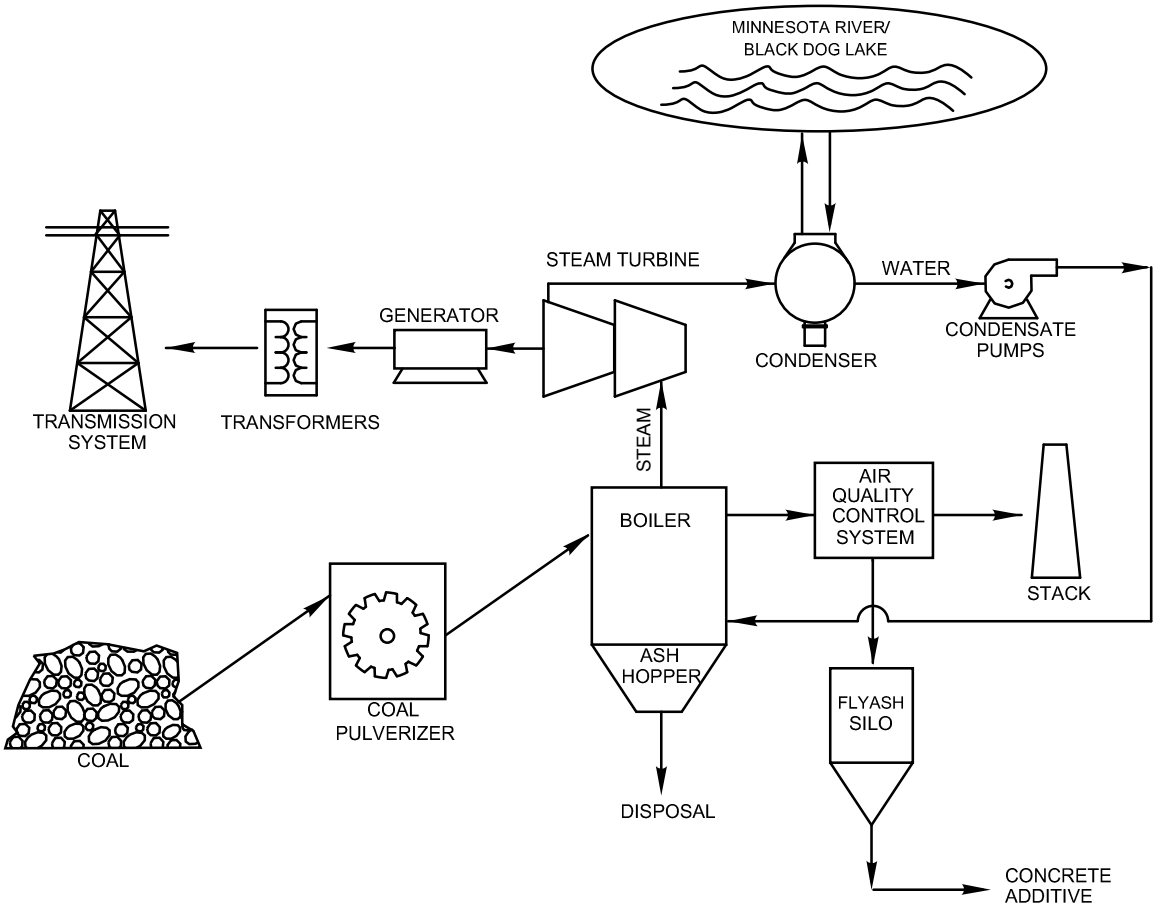
If the units continue to operate beyond the proposed 2016 retirement date, they will require significant investments due to aging equipment and pending regulatory changes.

In our 2007 Resource Plan, we indicated we would be studying options for Units 3 and 4. The submittal of this Certificate of Need filing is the result of

the evaluation process that we have completed and discuss in our 2010 Resource Plan.

The process by which Units 3 and 4 convert the energy in coal (or natural gas) to electrical energy for customers is shown schematically below in Figure 5-1.

Figure 5-1: Coal Fired Plant Schematic Diagram



The process begins with the conveyance of coal into the Plant where it is pulverized and then blown into the boiler and combusted. The exhaust from the boiler passes through an electrostatic precipitator that removes fly ash in the exhaust stream before going up the Plant stack. The heat generated by the boiler is used to convert water to steam that then passes through a turbine to turn the turbine rotors. The turbine shaft is connected to a generator that converts the rotational mechanical energy from the turbine shaft to electrical energy. After transferring its usable energy in the turbine, the steam is cooled further in a condenser and then returned to the boiler to repeat the cycle.

Table 5-1: Existing Black Dog Generating Plant Units 3 and 4 Operational Information

Description	Unit 3	Unit 4
General Data		
Nominal Generating Capability	89 MW Net	164 MW Net
Operating Cycle	Steam Rankine	Steam Rankine
Annual Capacity Factor	< 60 percent	< 70 percent
Actual Efficiency	30.3% (net)	32.5% (net)
Annual Availability	78%	90% (Apr – Oct)
Land Requirement	< 1 acre for each Unit, total Plant site is approximately 35 acres out of a 1,900 acre site	
Fuel Data		
Fuel Source	Low-sulfur western coal Natural Gas – CenterPoint	Low-sulfur western coal Natural Gas – CenterPoint
Fuel Requirement Primary - Coal Secondary – Natural Gas	49.9 tons/hr coal with 0.16 million SCF/hr natural gas	94.5 tons/hr coal with 0.13 million SCF/hr natural gas
Heat Input (HHV)	1001 MMBTU/hr	1,724 MMBTU/hr
Fuel (Coal) Heat Value (HHV)	8,450 BTU/lb	8,450 BTU/lb
Fuel (Coal) Content:		
Sulfur	0.21%	0.21%
Ash	5.2%	5.2%
Moisture Content	27.5%	27.5%
Water Use	**Entire Plant Use Shown Below**	
Maximum Groundwater Pumping Rate	250 GPM peak, 200 GPM daily average	
Average Annual Groundwater Use	37 million gallons or 114 acre-feet (past 5 year annual average)	
Annual Surface Water Consumption	104,000 million gallons or 319,000 acre-feet (past 5 year annual average)	

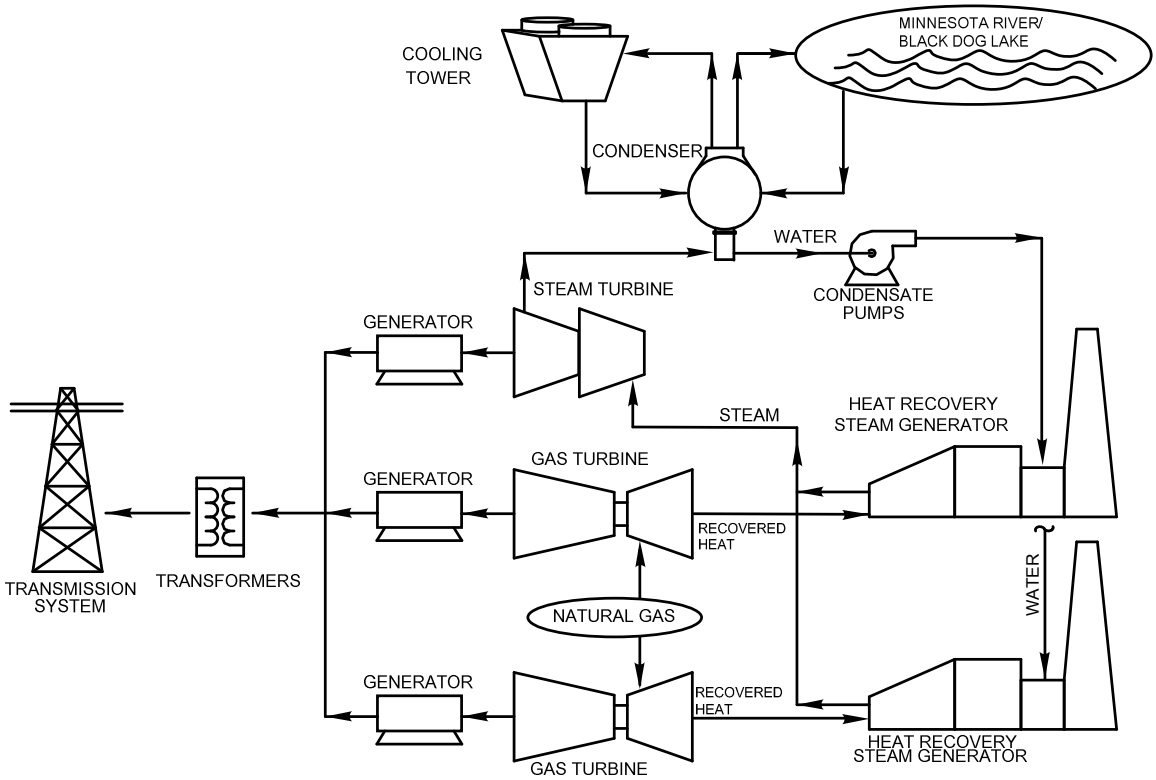
Units 3 and 4 are currently used as intermediate to base load facilities.

5.2 Description of Proposed Fuel and Operating Cycle

Combined cycle is an electric generating technology in which electricity is produced from otherwise lost heat exiting from one or more combustion turbines. The heat exiting the combustion turbine(s) is routed to a HRSG to generate steam for utilization by a steam turbine-generator set. This process increases the efficiency of the electric generating unit. The steam from the

steam turbine generator is exhausted to the condenser to be converted back to water for reuse in the HRSG. The condenser requires cooling water to cool the steam and convert it back to water. In the cooling process heat is transferred to the cooling source. The Project is expected to use a combination of the Minnesota River and a cooling tower for cooling as shown below in Figure 5-2.

Figure 5-2: Schematic Diagram of a 2 on 1 Combined Cycle Facility



Major components of the Project include:

- Combustion Turbine-generators
- HRSGs and exhaust stacks
- Steam turbine generator, condenser and cooling tower
- Transformers

Combustion Turbine-generators
The design capacity of the Project is based on the performance characteristics of an F class combustion turbine (similar to the existing Unit 5) with supplemental firing to increase steam generation to the steam turbine. In a typical unfired combined cycle plant, the combustion turbine capacity is approximately double the steam turbine capacity.

Each combustion turbine-generator consists of the following equipment in series:

Inlet Air Filter

Compressor, where air is drawn in and compressed

Combustor, where the air/fuel mixture is ignited

Power Turbine, where the combusted gases expand to rotate a turbine

Generator set

HRSG and Exhaust Stacks
The Project includes two HRSGs – one matched with each combustion turbine. The exhaust gases exit each combustion turbine and flow directly into the HRSG. Inside the HRSG, the hot exhaust gases are directed across the heat transfer tube surfaces causing the water in the tubes to boil and change into steam. The HRSGs are also equipped with natural gas-fired duct burners that can be used to input additional heat to increase the steam generating capacity of the HRSGs. Each HRSG will be approximately 95 feet tall, 40 feet wide, and 140 feet long.

After passing through the HRSG, exhaust gases from each combustion turbine generator will discharge through a steel stack. Each stack will be approximately 19 feet in (inside) diameter.

The two combustion turbines will provide exhaust heat to produce sufficient steam to generate approximately 50 percent more output with the steam turbine. Supplemental duct firing of the HRSGs to increase their steaming rate will allow the Project to capture the full load capability of the steam turbine during periods when peak output is desired.

Steam Turbine Generator, Condenser and Cooling Tower
A single steam turbine will receive steam produced by the two HRSGs. Steam received from the HRSGs will be expanded through a reheat steam turbine and will rotate the turbine shaft. The energy produced by the expanding steam will rotate the turbine shaft, which drives a generator to produce electrical power.

Exhaust steam from the steam turbine will be condensed within a water-cooled steam surface condenser. The condensed steam collects in the bottom of the condenser from which it is pumped back to the HRSGs to be reused to generate steam. Cycle heat removed from the condensing steam in the condenser is absorbed by circulating water flowing through the condenser tubes. Heat absorbed by the circulating water will be rejected to the river, or to the cooling tower. Circulating water pumps will pump circulating water from the river intake or the cooling tower through the condenser to Black Dog Lake or the cooling tower.

Transformers
The three generator stepup transformers will be located next to the generation block. The transformers increase the output voltage of the three generators to the 345 kV substation voltage. Auxiliary transformers will be used to convert some of the output power to lower voltages for use in the Project's auxiliary equipment.

5.3 Location and Land Use

The Project will be located on 35 acres within the exiting Plant site. The Plant site is located in Burnsville, Minnesota and is approximately 15 miles south of Minneapolis and east of the City of Eagan (see Figure 1-1).

The Plant is located in Township 27N, Range 24W, Sections 23 and 24 in Dakota County. The Plant for the most part is separated from commercial and residential areas by Black Dog Lake, the Union Pacific Railroad and the Company's railroad spur, Black Dog Park and the Minnesota River. There is forest land along each side of the Union Pacific Railroad and open and scattered forest south of Black Dog Lake where the two proposed double circuit 345 kV transmission lines will connect with the existing 345 kV transmission lines.

Current USGS Landuse/Landcover database information characterizes the Plant site as consisting of primarily Developed and Barren land with a small segment of Open Water overlaying the Plant ponds and intermittent strips of deciduous forest outlying the Plant's southern boundary and along the Xcel Energy railroad spur.

The Plant property covers about 1,900 acres south of the Minnesota River in Burnsville. The total acreage includes the Plant site covering about 80 acres, which entails the powerhouse, coal yard, substation, settling ponds, and Black Dog Lake (used for cooling) covering about 500 acres. The majority of the remaining property (1,250 acres) is managed as part of the Minnesota Valley National Wildlife Refuge under a 1982 lease and agreement with the U.S. Fish and Wildlife Service.

Established in 1976, the Minnesota Valley National Wildlife Refuge stretches over 50 miles between Fort Snelling State Park and Belle Plain, Minnesota, and provides habitat for a large number of migratory waterfowl, fish, and other wildlife species
(FWS, 2010; http://www.fws.gov/Midwest/MinnesotaValley/intro.html). The Refuge offers a variety of year-long and free outdoor recreational activities, and has two education and visitors centers, which are located over 5 and 40 miles, respectively, from the Plant site. The Minnesota Valley National Wildlife Refuge is well known for bird watching, which is available year-round. Other recreational opportunities include wildlife observation, wildlife photography, hunting, fishing, environmental education, and interpretation. According to the FWS' website
(2010; http://www.fws.gov/Midwest/MinnesotaValley/intro.html), overall management of the Refuge involves "restoring wetlands, grasslands, and oak savannas, enhancing aquatic plant diversity through water level management, grassland management, exotic species control, and water quality monitoring."

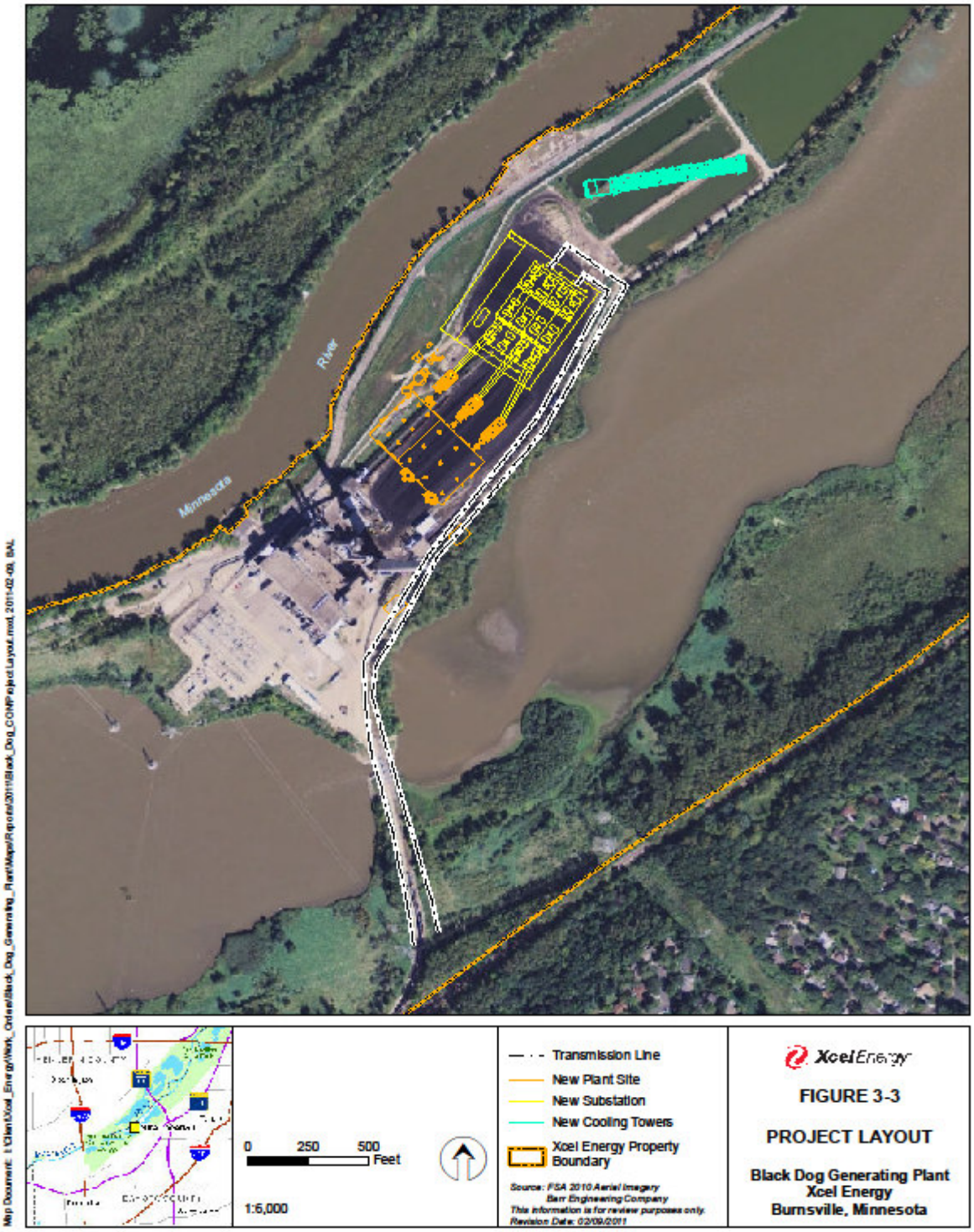
We began a cooling lake drawdown program in 1989 in cooperation with the U.S. Fish and Wildlife Service to enhance wetland vegetation growth in Black Dog Lake and thereby increase migratory bird use. The cooling ponds allow some birds such as the American woodcock to remain in the area longer in winter. The Plant site and proposed Project layout is shown in Figure 5-3.

About 350 feet south of the Project area is Black Dog Park, a 38-acre park that includes softball/baseball fields, a football field, walking trails and natural areas (http://www.ci.burnsville.mn.us/index.aspx?NID=269). The closest

park-related facilities to the Project include a softball/baseball field, which is located about 750 feet west and primarily used during the spring, summer, and autumn months. About 200 feet south of the Project area is a walking trail along the south side of Lyndale basin of Black Dog Cooling Lake. The Project is not expected to impact Black Dog Park or walking trails.

In addition to the previously discussed Minnesota Valley National Wildlife Refuge, the primary tourism activities in the region include camping, recreational use of the regions lakes for fishing and boating, bicycling, hiking, bird or wildlife viewing, or cross country skiing.

Figure 5-3: Project Layout



5.4 Structures and Structure Height

The Project components will be located primarily within the existing Plant coal yard area. A new 425 foot by 280 foot by 140 foot tall structure will be built in the current coal yard area. New components that will be located in the new enclosed structure are two combustion turbine-generator sets, two HRSGs, and one steam turbine-generator. Two air inlet filters will be located on the exterior of the structure and five new transformers will be located adjacent to the new facility structure. A new 345 kV substation will be constructed next to the generation block. Three water tanks and two ammonia storage tanks will also be added outside the new Plant structure. The exhaust stacks will be approximately 230 feet tall and will be located adjacent to the new structures. The new transmission towers will be between 90 and 110 feet tall. The transmission infrastructure associated with the Project is described in Section 5.8. A cooling tower will likely be located where the current ash ponds reside. The height of the cooling tower will be approximately 70 feet tall.

5.5 Project Output

The output of the Project depends on ambient weather conditions (primarily temperature and humidity) and the operating mode of the HRSG (with or without duct-firing). For purposes of this application, nominal generating capacity is considered to be about 700 MW. The Project will operate at maximum efficiency without duct firing. Therefore, it is a competitive unit to meet intermediate load needs.

5.6 Project Sizing

The design capacity of the Project is based on the current performance characteristics of an F class combustion turbine (similar to the existing Unit 5) with supplemental firing to increase steam generation to the steam turbine. In a typical unfired combined cycle plant, the combustion turbine capacity is approximately double the steam turbine capacity. The two combustion turbines will provide exhaust heat to produce sufficient steam to generate approximately 50% more output with the steam turbine. Supplemental firing of the HRSGs to increase their steaming rate will allow the Project to capture

the full load capability of the steam turbine during periods when peak output is desired.

5.7 Fuel Use

The Project will be fueled entirely by natural gas with no backup fuel. We expect to secure firm natural gas supply contracts.

5.8 Transmission

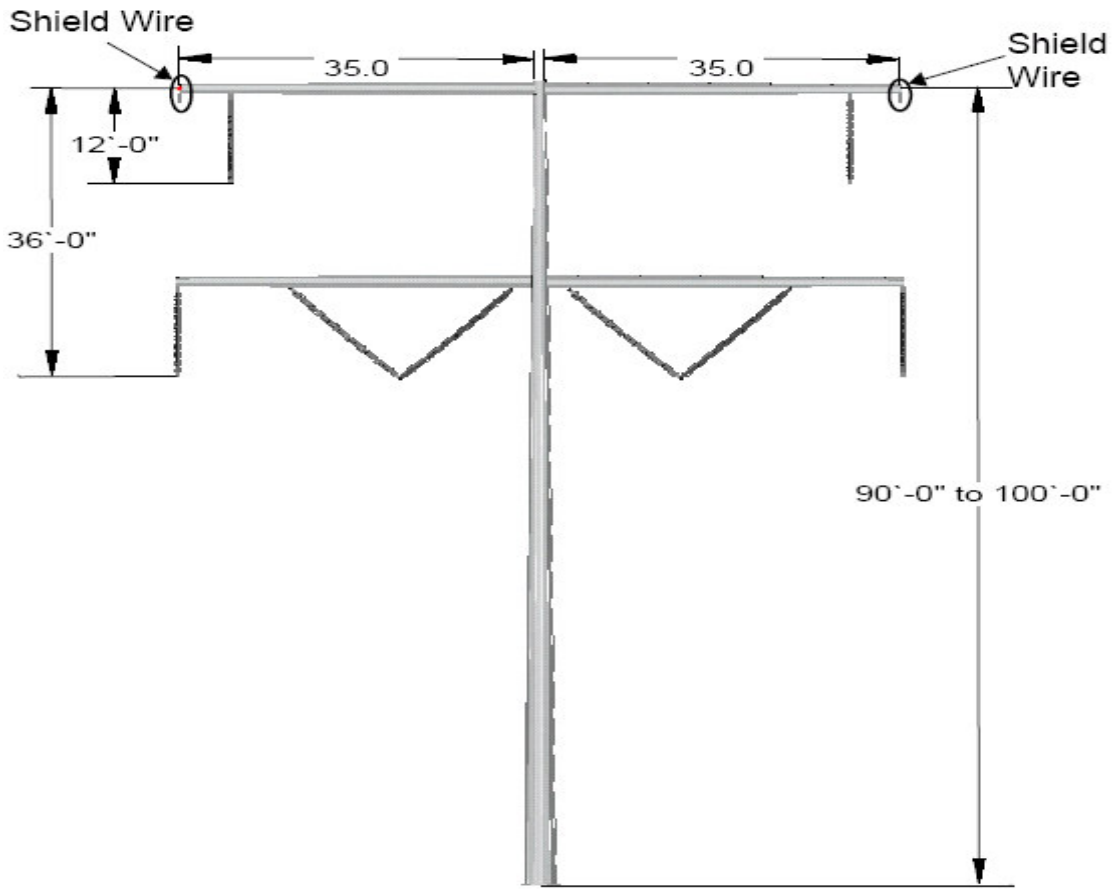
The Project will be connected to the bulk transmission system through a new 345 kV substation. The electric transmission components of the Project consists of building two double circuited, 345 kV transmission lines that will be approximately 4,000 feet long and reconfiguring a 1,000 to 1,500 foot-long section of existing transmission line. The reconfiguring stems from the need for the new lines to cross over two existing 115 kV lines, precipitating the need to adjust the height of the 115 kV lines for this purpose. The proposed location of the substation and the proposed route of the 345 kV lines are shown above on Figure 5-3. The new lines will connect the new 345 kV substation to the existing Blue Lake to Prairie Island 345 kV transmission line and the Blue Lake to Inver Hills 345 kV transmission line. Both of these lines currently run through the Plant site so all transmission work will be done within existing Xcel Energy property.

The proposed structures (see Table 5-2 and Figure 5-4 below) for the 345 kV double circuit lines will be about 90 to 110 feet tall and will have an average span between 300 and 500 feet. The finish of the proposed poles will be galvanized steel. The existing transmission line structures in this area are wood poles of H-frame construction, and galvanized steel lattice design. The proposed steel poles will give the new transmission line a somewhat cleaner and more modern appearance. The conductor will be bundled, 795 KCmil 26/7 ACSR. Conductor Specifications are presented in Appendix E.

Table 5-2: Structure Design Summary

Line Type	Structure Type	Structure Material	Right-of-Way Width (feet)	Structure Height (feet)	Foundation	Foundation Diameter (feet)	Span Between Structures (feet)
345 kV Double Circuit	Single pole,	Galvanized steel	150	90-110	Concrete	8 to 10 foot concrete	300 to 500

Figure 5-4: Double Circuit Transmission Line Structure



5.9 Natural Gas Pipeline

CenterPoint Energy currently serves the Plant site. We will be securing additional natural gas supply through a competitive process beginning in early 2012. We anticipate that the successful bidder will file for a route permit and other necessary permits to replace the existing pipeline serving the Plant with a new higher pressure natural gas line.

5.10 Construction

5.10.1 Generation Block

Generation block construction will begin after approvals are obtained. Site preparation and fill to bring the Project area above the 100 year flood level is anticipated to start in 2012. Installation of pilings and construction of foundations will start the following year. Building erection and installation of the large components would occur in 2014. In 2015, construction completion and startup of the facility would occur.

The Project is expected to be in commercial operation by January 2016. Below we describe the sequence of activities that occur during transmission line construction and some of the measures that can be taken to mitigate potential impacts during construction.

5.10.2 Transmission

Line Construction

The transmission line construction will begin after regulatory approvals are obtained, soil conditions are established and final design is complete. The precise timing of the construction will take into account various requirements that may be in place due to permit conditions, system loading issues and available workforce.

The actual construction will follow standard construction and mitigation practices that have been developed based on past project construction experience. These best practices address right-of-way clearance, staging, erecting transmission line structures and stringing transmission lines. Construction and mitigation practices to minimize impacts will be developed based on the proposed schedule for activities, permit requirements, prohibitions, maintenance guidelines, inspection procedures, terrain, and other practices.

Environmentally sensitive areas may require special construction techniques. These may include additional erosion control measures to protect steep slopes, matting to minimize soil disturbance/compaction, and/or remediation associated with unanticipated contaminated soils.

Up to 15 to 25 construction workers will be used at any one time to construct the double circuit overhead transmission line.

Right-of-Way Restoration and Clean Up
During the construction of the transmission line, crews will attempt to limit ground disturbance wherever possible. However, areas are disturbed during the normal course of work, which can take several weeks in any one location. After construction, disturbed areas are restored to their original condition to the maximum extent practicable. Vegetation that is disturbed or removed during transmission line construction will naturally reestablish to pre-disturbance conditions. Areas with significant soil compaction and disturbance from construction activities along the proposed transmission line corridor may require assistance in reestablishing the vegetation stratum and controlling soil erosion. Commonly used methods to control soil erosion and assist in reestablishing vegetation include, but are not limited to:

- erosion control blankets with embedded seeds
- silt fences
- matting

These erosion control and vegetation establishment practices are regularly used in construction projects and long-term impacts are minimized by utilizing these construction techniques.

Substation Construction
Substation construction will begin after approvals are obtained, soil conditions are determined and the design is completed. The precise timing of construction will take into account various requirements that may be in place due to permit conditions, available workforce, and materials. Construction and mitigation practices to minimize impacts will be developed based on the proposed schedule for activities, permit requirements, prohibitions, maintenance guidelines, inspection procedures, terrain, and other practices.

5.11 Project Operation

5.11.1 Project Dispatch

The Project will be integrated into our remote dispatch control center. We expect to use the Project's unfired capability (and maximum efficiency point) for intermediate load service, dispatching it after all incrementally cheaper and "must run" units have been dispatched. The additional capacity of the Project, available through supplemental firing of the HRSG, will be utilized for peak demand periods.

5.11.2 Load Following

The Project will also serve to load follow as system load requirements change. The Project will be able to commence start up after a 30-minute notice and will have the ability to ramp at approximately 5 to 10 MW per minute depending on the pre-existing steam turbine condition.

5.11.3 Capacity Factor

The Project is expected to be dispatched 5 days per week, 16 hours per day with an initial annual capacity factor of 35%. It is expected that the capacity factor can rise to higher levels after operating for a few years.

We modeled the financial and operating impact of the Project using the Strategist computer model. Among other outcomes, the model illustrates the dispatch characteristics for the modeled system. The model shows the Project initially being utilized to support the system at a 35% capacity factor, because of the operating economics of the System and the Project's load following capability.

5.12 Project Operational Data

Operational data requirements are presented below in Table 5-3.

Table 5-3: Project Operational Information

Rule Reference	Description	Project Data
7849.0250, A(1)	Nominal Generating Capability	about 700 MW
7849.0250, A(2)	Operating Cycle	Combined Cycle
7849.0250, A(2)	Expected Annual Capacity Factor	35 percent
7849.0250, C(2)	Service Life	35 Years
7849.0250, C(3)	Estimated Average Annual Availability	> 90 percent
7849.0320, A	Estimated Land Requirements	35 acres on existing site
7849.0320, E (1)	Estimated Maximum Groundwater Pumping Rate for Site Surface Water Appropriation	250 GPM peak, 200 GPM daily average, no change from current plant 447 cfs for Project, 633 cfs for Site
7849.0320, E (2)	Estimated Annual Project Groundwater Appropriation (assuming RO purification process)	17 million gallons/year or 51 acre-feet/year (34% of site appropriation)
7849.0320, E (3)	Annual Project Surface Water Consumption	215,100 acre-feet (50% of site appropriation)

Below is Figure 5-5 that provides a preliminary artist's rendition of what the repowered facility will look like.

Figure: 5-5: Preliminary Rendering Diagram

5.13 Maintenance Requirements

5.13.1 Generation

The scope and frequency of maintenance work on the Project's combustion turbine, steam turbine, HRSG, and the balance of Plant equipment will be in accordance with power industry standards and equipment manufacturer recommendations.

The frequency of maintenance for major combustion turbine components is based on the number of unit start-ups and firing hours and falls into three categories:

- Combustor inspections typically occur every 450 starts or 12,500 firing hours and require a 6-7 day outage,
- Hot gas path inspection and component replacement occurs about every 900 starts or 25,000 firing hours requiring an 11 to 13-day outage, and

- Major overhauls are scheduled about every 1800 starts or 50,000 firing hours and require a 23 to 25 day outage.

The HRSG should require only periodic inspection and minor maintenance that can be scheduled to coincide with outages of the combustion turbine. Major overhaul of the steam turbine-generator, condenser and associated equipment will be necessary every six to eight years. Balance of plant and cooling tower equipment should only require routine maintenance.

5.13.2 Transmission

Periodic inspections, maintenance and damage repair will be performed during the life of the transmission facilities to ensure their continued integrity. Personnel on foot, snowmobile, ATV, or pick-up truck will typically perform annual inspections. If problems are found during inspection, repairs will be performed. Aerial inspections are conducted more frequently.

The right-of-way will be managed to remove vegetation that interferes with the operation and maintenance of the lines. Current practice provides for the inspection of major transmission line right of ways every five years to determine if clearing is required. Right-of-way clearing practices include a combination of mechanical and hand clearing, along with herbicide application where allowed to remove or control vegetation.

The estimated service life of the proposed transmission lines for accounting purposes is approximately 40 years. However, practically speaking, high voltage transmission lines are seldom completely retired. Transmission infrastructure has very few mechanical elements and is built to withstand weather extremes that are not normally encountered. With the exception of severe weather such as tornadoes and heavy ice storms, transmission lines rarely experience structural and/or electrical failures. Transmission lines are automatically taken out of service by the operation of protective relaying equipment when a fault is sensed on the system. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent. As a result, the average annual availability of transmission infrastructure is very high, in excess of 99%.

The principal operating and maintenance cost for transmission facilities is the cost of inspections, done every other year by ground inspection in metro areas. Annual operating and maintenance costs for transmission lines in

Minnesota and the surrounding states vary. Actual line-specific maintenance costs depend on the setting, the amount of vegetation management necessary, storm damage occurrences, structure types, materials used, and the age of the line.

Substations require a certain amount of maintenance to keep them functioning in accordance with accepted operating parameters and the National Electric Safety Code ("NESC") and North American Electric Reliability Corporation ("NERC") requirements. Transformers, circuit breakers, batteries, protective relays, and other equipment need to be serviced periodically in accordance with the manufacturer's recommendations. The substation site must be kept free of vegetation and adequate drainage must be maintained. The estimated service life of the proposed substation facilities for accounting purposes is 38 years.

5.14 Project Cost Evaluation

In our 2010 Resource Plan analysis we estimated the capital cost of the proposed facility to be approximately $600 million. Updated and more detailed cost estimates have been made and are presented in the format requested by Minnesota Rule 7849.0250 in Appendix H. These costs include the repowered plant costs, the substation, interconnecting transmission line costs and the incremental costs of a cooling tower. The Project's economic impact on the System was also evaluated using the Strategist model as described in Chapter 4. The model compared the Project to retiring the units and using simple cycle generating resources to meet demand (Alternative Generation), extending the life of the units such that they can continue to operate on coal, and replacing with a new biomass plant. The model shows the Project with the lowest overall cost of the alternatives modeled (see Table 4-1). In Chapter 4 we have included a sensitivity analysis table that demonstrates the effect of including the complete cost of a cooling tower for the entire plant site including existing Unit 5/2.

6 Environmental Information

The Project provides numerous environmental benefits as it allows for retiring aging coal-fired generation technology and replacing it with flexible, clean and efficient natural gas-fired combined cycle technology. These benefits include:

- Enabling Xcel Energy's system to operate reliably with increased wind generating capacity;
- Utilizing an established site and existing transmission to renew and expand our fleet thereby avoiding new generating sites and transmission corridors in the state;
- Taking advantage of substantial existing infrastructure available for use at the plant site, such as transmission lines, natural gas pipeline corridors, water and wastewater systems, transportation infrastructure and other facilities; and
- Reducing GHGs and other air emissions.

This section discusses the environmental impacts of the proposed Project, and provides the environmental data required under Minnesota Rule 7849.0310, 7849.0320 and 7849.0330. The environmental impacts of the alternatives to the Project are discussed in Chapter 4.

6.1 Air Impacts

6.1.1 Air Emissions

This subsection addresses the requirements of Minnesota Rule 7849.0320(D) that states an applicant shall provide "*for fossil fueled facilities:*

(1) the estimated range of trace element emissions and the maximum emissions of sulfur dioxide, nitrogen oxides, and particulates in pounds per hour during operation at rated capacity; and

(2) the estimated range of maximum contributions to 24-hour average ground level concentrations at specified distances from the stack of sulfur dioxide, nitrogen oxides, and particulates in micrograms per cubic meter during operation at rated capacity and assuming generalized worst-case meteorological conditions;"

and Minnesota Rule 7849.0330(A) states an applicant shall provide "*for overhead transmission facilities:*

(3) a discussion of ozone and nitrogen oxide emissions attributable to the transmission facility;"

Natural gas-fired combined cycle technology is among the most efficient and cleanest means of generating utility-scale electricity. Natural gas combustion generates significantly less carbon dioxide, particulate matter, sulfur dioxide, and toxic air emissions (including mercury) than oil or coal.

The primary constituents of concern resulting from combustion of natural gas are NO_x, CO and VOCs. The Project will control NO_x emissions through use of dry low-NO_x burners and SCR. Good combustion practices and oxidation catalysts will be used to control emissions of fine particulates, CO, and VOCs.

Quantities of most types of air emissions from the Project will be significantly lower than from the existing coal fired units. VOCs will be higher on an annual basis than from the coal fired units because of emissions during startup of the combined cycle units. During startup, combustion turbines must be held at a low load until the HRSG and steam turbine reach manufacturer-specified temperatures, to avoid equipment damage. Additionally, SCRs and oxidation catalysts do not control emissions efficiently until combustion gases reach a certain temperature not achieved at low loads. Preliminary estimates are that NO_x, SO_2, and Hg emissions will be reduced 96 to 99% on an annual basis, and that particulate matter and carbon dioxide emissions will be reduced 50 to 65% on an annual basis from the current units' operations. To calculate these reductions we used an annual average from a 24 month period during 2008-2010.

Emissions categories regulated by the federal Prevention of Significant Deterioration ("PSD") program will be netted against the current emissions from Units 3 and 4. Preliminary results of the netting indicate that PSD regulations will be in effect for VOCs. The main outcome of PSD will be VOC emission limits in the air emissions permit, based on a Best Available Control Technology analysis.

Table 6-1 presents the estimated air emissions from the new combined cycle units. Estimated impacts to ambient air quality summarized in Table 6-2 are based on preliminary modeling using an EPA approved dispersion model (AERMOD).

Table 6-1: Estimated Project Air Emissions

EPA Criteria Pollutants		
Pollutant	**Emission Rate** Two Units Without Duct Firing, at Rated Capacity (average ambient conditions, base load) (lbs/hour)	**Emissions[1]** Two Units With Duct Firing, at Projected Annual Operating Hours (tons/year)
SO_2	4	6
NO_X	66	132-157
PM_{10}	41	67
CO	16	85-209
VOCs	19	104

Hazardous Air Pollutants (HAPs)			
Pollutant	**Emissions[2]** Two units at Projected Annual Operating Hours (tons/year)	Pollutant	**Emissions[2]** Two units at Projected Annual Operating Hours (tons/year)
1,3-Butadiene	0.00	Hexane	0.55
1,4 Dichlorobenzene	0.00	Lead	0.00
Acetaldehyde	0.24	Manganese	0.00
Acrolein	0.04	Mercury	0.00
Arsenic	0.00	Naphthalene	0.01
Benzene	0.07	Nickel	0.00
Beryllium	0.00	Polycyclic Aromatic Hydrocarbons	0.01
Cadmium	0.00	Polycyclic Organic Matter	0.00
Chromium	0.00	Propylene Oxide	0.18
Cobalt	0.00	Selenium	0.00
Dioxins	0.00	Toluene	0.80
Ethylbenzene	0.20	Xylenes	0.39
Formaldehyde	4.43		

[1]Annual emissions from two combustion turbines, with startup and shutdown periods, at 3,066 operating hours each and HRSG duct firing at 438 hours each.
[2]Annual emissions from two combustion turbines at 3,066 operating hours each and HRSG duct firing at 438 hours each. Emissions numbers do not account for reduction in organic HAPs achieved with oxidation catalyst.

Table 6-2: Estimated Maximum Contributions to Ambient Air Quality

Pollutant	Units 3 and 4 Repowering Project Contribution to Ground-level Concentrations ($\mu g/m^3$)	National and Minnesota Ambient Standards ($\mu g/m^3$)
SO_2 (24-hour)	0.8	365
NO_2 (24-hour)	14.1	--
PM_{10} (24-hour)	6.3	150

Note: Based on two combustion turbines and duct burners, 100% loaded.

6.1.2 Transmission Air Emissions

The potential air emissions associated with the Project transmission lines are negligible. However, there is potential for ozone and nitrogen oxide due to corona. Corona consists of the breakdown or ionization of air within a few centimeters of conductors which can produce ozone and oxides of nitrogen in the air surrounding the conductor. Typically, some imperfection such as a scratch on the conductor or a water droplet is necessary to cause corona. Ozone is not only produced by corona, but also forms naturally in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants, such as hydrocarbons from auto emissions. The natural production rate of ozone is directly proportional to temperature and sunlight, and inversely proportional to humidity. Thus humidity or moisture, the same factors that increase corona discharges from transmission lines, inhibit the production of ozone. Ozone is a very reactive form of oxygen molecules and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, it is relatively short lived. For a 345 kV transmission line, the conductor gradient surface is usually below the air breakdown level.

Currently, both state and federal governments have regulations regarding permissible concentrations of ozone and NO_2. The applicable standards for these compounds in parts per million ("ppm") are presented in Table 6-3.

Table 6-3: Applicable Ambient Air Quality Standards for Transmission Projects

Pollutant	Level	Averaging Time	National or Minnesota Standard
Nitrogen Dioxide	0.100 ppm	1-hour	National
Nitrogen Dioxide	0.053 ppm	Annual	National
Nitrogen Dioxide	0.05 ppm	Annual	Minnesota
Ozone	0.075 ppm	8-hour	National
Ozone	0.08 ppm	8-hour	Minnesota

For the overhead 345 kV/345 kV double circuit design with both circuits in service on the proposed route, the predicted ozone concentration is 0.0007 ppm in foul weather (worst case) conditions. The corona loss estimate is 0.1 W/m. These calculations were obtained from the Software Applications for the EPRI AC Transmission Line Reference Book, 200kV and Above, Third Edition.

The result is well below both federal and state standards. Most calculations of the production and concentration of ozone assume high humidity or rain, with no reduction in the amount of ozone due to oxidation or air movement.

6.1.3 Fugitive Dust

Site preparation and construction activities to include construction of the transmission lines will produce small amounts of fugitive dust from earth-moving, construction and right-of-way clearing. Fugitive emissions from earth-moving and construction will be controlled by watering or applying dust suppressants to exposed soil surfaces as necessary. Adverse impacts to the surrounding environment will be minimal because of the short and intermittent nature of the overall emissions and dust-producing earth-moving, construction and right-of way clearing processes.

Fugitive dust emissions will not be generated in any significant amounts during operation of the Plant and will be reduced with the elimination of coal as a fuel. Adverse impacts to the surrounding environment will be minimal because of the short and intermittent nature of the emission and dust-producing construction phases.

6.2 Noise Impacts

This subsection addresses the requirements of Minnesota Rule 7849.0320(I) which requires an applicant to provide:

"the potential sources and types of audible noise attributable to operation of the facility;"

and Minnesota Rule 7849.0330 subpart A (5) that states an applicant shall provide:

"a discussion of the characteristics and estimated maximum and typical levels of audible noise attributable to the transmission facilities;"

Generation Noise

Noise from the generating units is not expected to have a significant impact. The generating units will be in compliance with state and local noise standards. The generation is located in an isolated area with the nearest residences located more than 1,500 feet away from the Plant. Noise from the operation of the repowered units is expected to be predominantly low frequency noise, as is noise from traffic. Noise from the generation operations will not significantly impact the acoustical environment given the noise control technology that will be employed by the new generating units. In addition, existing Units 3 and 4 will be retired along with the noise associated with coal trains and other coal and ash handling processes.

To control potential generation noise impacts and meet applicable standards, the Company will potentially employ several noise mitigation measures including:

1. Totally enclosed generation building containing the major generation equipment including the combustion turbines, HRSGs, feedwater pumps and steam turbine
2. HRSG flue gas stack silencers
3. Low noise transformer packages
4. Generation Building acoustical louvers
5. Generation Building roof fan noise reduction packages
6. Combustion turbine generator air inlet silencer
7. Generation Building wall and ceiling insulation
8. Steam vent silencers
9. Diesel engine silencers

Thus, generation operation is expected to be 50 dBA at the nearest residence which meets the state noise standards established by the MPCA. Noise will be generated by the construction of the Project. Construction noise will be predominantly from intermittent sources originating from diesel engine driven construction equipment. Potential noise impacts will be mitigated by proper muffling equipment fitted to construction equipment, as well as restricting activities if necessary. Additional noise will be generated by pile driving activities. Pile driving activities are expected to last three months and to occur in the first half of 2013.

Transmission Noise

Overhead transmission conductors produce noise under certain conditions. The level of noise depends on conductor conditions, voltage level, and weather conditions. Generally, activity-related noise levels during the operation and maintenance of substations and transmission lines are minimal.

Noise emission from a transmission line occurs during certain weather conditions. In foggy, damp, or rainy weather, power lines can create a crackling sound due to the small amount of electricity ionizing the moist air near the wires. During heavy rain the background noise level of the rain is usually greater than the noise from the transmission line. As a result, people do not normally hear noise from a transmission line during heavy rain. During light rain, dense fog, snow, and other times when there is moisture in the air, transmission lines can produce noise.

However, noise levels produced by a 345 kV transmission line are generally less than outdoor background levels and are therefore not typically audible. The noise generated from the transmission lines is not expected to exceed the background noise levels and would therefore not be audible at any receptor location.

6.3 Water Needs

Water usage associated with operation of the Project will be similar to that of the existing Plant, so the Project will not have a major incremental impact on water supplies. Details of expected water usage required by Minnesota Rule 7849.0320(E) are provided in Table 5-3.

Surface water appropriated from the Minnesota River is currently used for cooling water and that source will be used to supply the cooling water for the Project as well. The total surface water appropriations for the site will be

within the existing MnDNR Water Appropriations Permit (#1961-0270) limitations. For once-through cooling, the withdrawal rate will be higher than in recent years but similar to operations with four steam turbines in the late 1990's. An option for closed cycle mode with a cooling tower will result in significantly lower withdrawal volumes when operating in such a mode. Moreover, when in closed cycle mode, the evaporative losses through a cooling tower are expected to be higher than through the cooling lake ponds while in the once-through mode.

The closed cycle mode is anticipated to help address the fish protection requirements of EPA's Clean Water Act Section 316(b) for existing facilities. Additionally, the use of recycled water for cooling tower makeup is under consideration. The requirements and details of implementation of the cooling water needs for the Project will be part of the NPDES Permit amendment/approval (refer to section 2.5.4). The existing Plant is currently operated with once-through cooling. As EPA is currently updating for the Section 316(b) rule, the Plant site is planning that a cooling tower will be needed to satisfy the expected rule update.

Groundwater from an existing site well will supply other water needs for the Project. No increase in the groundwater appropriation rate or annual withdrawal volume will be required for the Project. The annual withdrawal volumes for future site operations (new and existing units) are expected to be within the range of existing plant operations.

6.4 Waste Generation

Wastewater generation associated with operation of the Project will be similar to or reduced from that of the existing plant. The solid waste generation will be reduced because there will no longer be coal ash generated at the Plant.

Estimates of discharges to water and solid wastes attributable to operation of the Project, required by Minnesota Rules 7849.0320(F, G, and H), are provided in Table 6-4. All waste management activities will be conducted in accordance with applicable rules, regulations and permits.

The most significant discharge to water will be the continued discharge of cooling water to the Minnesota River. As part of the Project, a new cooling water structure for the combined cycle equipment will be constructed for discharge into Black Dog Lake.

Cooling tower operation will create the addition of cooling tower blowdown as a new discharge to surface waters or to the sanitary sewer depending on NPDES and MCES permitting. Other liquid or solid waste streams that could result from the addition of a cooling tower would be wastewater resulting from the treatment process for cooling tower make up water.

Sanitary wastewater will continue to be discharged to the existing sanitary sewer system. Other liquid wastes will stem from routine maintenance activities. No radioactive releases will occur as a result of the Project.

The Project will eliminate the annual generation of approximately 33,000 tons of coal combustion residue (coal ash) currently being generated from the operation of the existing coal-fired Units 3 and 4. Please note that approximately 78% of this material is being beneficially used as a Portland cement replacement in concrete.

As EPA is currently in the process of updating 316(b) regulations, the water discharges shown in Table 6-4 covers both once-through cooling and cooling tower surface water discharges.

Table 6-4: Liquid and Solid Wastes

Waste	Phase	Description	Generation Rate	Disposition Method
Project Cooling Water Discharge	Liquid	Once through cooling water discharge	70,000 MGPY (once through mode all year operation)	Discharge to Minnesota River via the cooling lake (Black Dog Lake) under NPDES permit
Cooling Tower Blowdown	Liquid	Cooling Tower Blowdown	521 MGPY (closed cycle mode all year operation)	Discharge to surface waters under NPDES permit or discharge to sanitary sewer
Process Water Blowdown	Liquid	HRSG Blowdown	3.6 MGPY	Discharge to surface waters under NPDES permit or discharge to sanitary sewer
Process Water Blowdown	Liquid	Evaporator Cooler Blowdown (Spring through Fall only)	0.4 MGPY at 20% capacity factor	Discharge to surface waters under NPDES permit or discharge to sanitary sewer
Roof/Yard Drain	Liquid	Surface / Building Runoff (quantity assumes complete runoff)	28.5 MGPY for 35 acres at 30 inches precipitation per year.	Discharge to surface waters under NPDES permit via settling pond.
RO Reject Water	Liquid	Water containing dissolved solids	3 MGPY	Discharge to surface waters under NPDES permit or

Waste	Phase	Description	Generation Rate	Disposition Method
		present in the raw water source except at a greater concentration.	20 gpm (max.) <0.14 mgy	discharge to sanitary sewer
Service Water	Liquid	Equipment wash water.	5.3 MGPY similar to present except during construction	Discharge to surface waters under NPDES permit or discharge to sanitary sewer
Sanitary Wastewater	Liquid	Domestic wastewater.	0.2 MGPY similar to present	Existing sewer system
Oil/Grease	Solid	Lubricants, hydraulic fluid, etc.	<20 barrels/yr	Manage used oil with a contract firm
Maintenance Materials	Solid	Oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, cleaning solvents.	<10 tons/yr	Dispose of properly as specially regulated, solid or hazardous waste and/or recycle as feasible and allowable
Cooling Tower Filter Waste	Solid	Residue from filtering cooling tower makeup water from Minnesota River	1230 tons/yr	Dispose of properly as specially regulated or solid waste or with dredge spoils
Settling Pond Accumulation	Solid	Maintenance cleaning of settled solids	500 tons/year	Dispose of properly as specially regulated or solid waste or with dredge spoils

6.5 Electric and Magnetic Fields

This subsection addresses the requirements of Minnesota Rule 7849.0330(A)(2) that states an applicant shall provide:

"a discussion of the strength and distribution of the electric field attributable to the transmission facility, including the contribution of air ions if appropriate;"

No adverse impacts from electric and magnetic fields associated with the Project transmission lines are expected.

The term electromagnetic field ("EMF") refers to electric and magnetic fields that are coupled together such as in high frequency radiating fields. For the lower frequencies associated with power lines (referred to as "extremely low frequencies" ("ELF")), EMF should be separated into electric fields ("EFs") and magnetic fields ("MFs"), measured in kilovolts per meter ("kV/m") and milligauss ("mG"), respectively. These fields are dependent on the voltage of

a transmission line (EFs) and current carried by a transmission line (MFs). The intensity of the EF is proportional to the voltage of the line, and the intensity of the MF is proportional to the current flow through the conductors. Transmission lines operate at a power frequency of 60 hertz (cycles per second).

6.5.1 Electric Fields

There is no federal standard for transmission line electric fields. The Commission, however, has imposed a maximum electric field limit of 8 kV/meter measured at one meter above the ground. *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota,* Docket No. ET-2/TL-08-1474, Order Granting Route Permit (*adopting* ALJ Findings of Fact, Conclusions and Recommendation at Finding 194 (April 22, 2010 and amended April 30, 2010)) (September 14, 2010).

The maximum EF, measured at one meter above ground, associated with the Project is calculated to be 4.32 kV/m. The calculated EFs for the Project are provided in Table 6-5.

Table 6-5: Calculated Electric Fields (KV/M) For Proposed 345 KV Transmission Line Designs (One meter above ground)

Structure Type	Maximum Operating Voltage (kV)	Distance to Proposed Centerline										
		-300'	-200'	-100'	-50'	-25	0'	25	50'	100'	200'	300'
345Kv Steel Pole Double Circuit Suspension Type	362	0.09	0.20	0.76	3.60	4.02	4.32	4.02	3.60	0.76	0.20	0.09

6.5.2 Magnetic Fields

There are presently no Minnesota regulations pertaining to MF exposure. The MF profiles around the proposed transmission line structures and conductor configuration proposed for the Project are shown in Table 6-6. MFs are calculated for the Project under two system conditions: the expected peak and average current flows as projected for the year 2015. The peak MF values are

calculated at a point directly under the transmission line and where the conductor is closest to the ground. The same method is used to calculate the MF at the edge of the right-of-way. The calculated MFs show that fields decrease rapidly as the distance from the centerline increases (proportional to the inverse square of the distance from source).

The MF produced by the transmission line is dependent on the current flowing on its conductors. Therefore, the actual MFs when the Project is placed in service are typically less than shown in Table 6-6. This is because the table represents the MF with current flow at expected normal peak based on projected regional load growth through 2015, the maximum load projection timeline available. Actual current flow on the line will vary with system conditions, so MFs would be less than peak levels during most hours of the year.

Table 6-6: Calculated Magnetic Flux density (milligauss) for Proposed 345 kV Transmission Line Design (One meter above ground)

Segment	System Condition	Current (Amps)	Distance to Proposed Centerline										
			-300'	-200'	-100'	-50'	-25	0'	25	50'	100'	200'	300'
345kV Steel Pole Double Circuit Suspension Type BDS-IVH& BDS-BLL	Peak	787/336	1.83	4.03	14.59	40.42	68.23	96.62	109.96	76.27	24.10	5.70	2.46
	Average	472/202	1.10	2.42	8.76	24.28	40.97	57.98	65.96	45.75	14.46	3.42	1.48

Considerable research has been conducted throughout the past three decades to determine whether exposure to power-frequency (60 hertz) MFs causes biological responses and health effects. Epidemiological and toxicological studies have shown no statistically significant association or weak associations between MF exposure and health risks. The possible impact of exposure to EMFs upon human health has also been investigated by public health professionals for the past several decades. While the general consensus is that EFs pose no risk to humans, the question of whether exposure to MFs can cause biological responses or health effects continues to be debated.

In 1999, the National Institute of Environmental Health Sciences ("NIEHS") issued its final report on "Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields" in response to the Energy Policy Act of 1992. The NIEHS concluded that the scientific evidence linking MF exposure with health risks is weak and that this finding does not warrant aggressive regulatory concern. However, because of the weak scientific evidence that supports some association between MFs and health effects, passive regulatory action, such as providing public education on reducing exposures, is warranted.

In 2007, the World Health Organization ("WHO") concluded a review of the health implications of electromagnetic fields. In this report, WHO stated:

> Uncertainties in the hazard assessment [of epidemiological studies] include the role that control selection bias and exposure misclassification might have on the observed relationship between magnetic fields and childhood leukemia. In addition, virtually all of the laboratory evidence and the mechanistic evidence fail to support a relationship between low-level [extremely low frequency] magnetic fields and changes in biological function or disease status. Thus, on balance, the evidence is not strong enough to be considered causal, but sufficiently strong to remain a concern. (WHO, 2007 at p. 12).

Also, regarding disease outcomes, aside from childhood leukemia, WHO stated:

> A number of other diseases have been investigated for possible association with ELF magnetic field exposure. These include cancers in children and adults, depression suicide, reproductive dysfunction, developmental disorders, immunological modifications and neurological disease. The scientific evidence supporting a linkage between ELF magnetic fields and any of these diseases is much weaker than for childhood leukemia and in some cases (for example, for cardiovascular disease or breast cancer) the evidence is sufficient to give confidence that magnetic fields do not cause the disease. (*Id.* at p. 12.)

Furthermore, in its "Summary and Recommendations for Further Study" WHO emphasized that: "The limit values in [ELF-MF] exposure guidelines [should not] be reduced to some arbitrary level in the name of precaution. Such practice undermines the scientific foundation on which the limits are based and is likely to be an expensive and not necessarily effective way of providing protection." (*Id.* at p. 12).

Although WHO recognized epidemiological studies indicate an association on the range of three to four mG, WHO did not recommend these levels as an exposure limit but instead provided: "The best source of guidance for both exposure levels and the principles of scientific review are international guidelines." *Id.* at pp. 12- 13. The international guidelines referred to by WHO are the International Commission on Non-Ionizing Radiation Protection ("ICNIRP") and the Institute of Electrical and Electronic Engineers ("IEEE") exposure limit guidelines to protect against acute effects. *Id.* at p. 12. The ICNIRP-1998 continuous general public exposure guideline is 833 mG and the IEEE continuous general public exposure guideline in 9,040 mG. In addition, WHO determined that "the evidence for a casual relationship [between ELF-MF and childhood leukemia] is limited, therefore exposure limits based on epidemiological evidence is not recommended, but some precautionary measures are warranted." *Id.* at 355-56.

WHO concluded that:

> given the weakness of the evidence for a link between exposure to ELF magnetic fields and childhood leukemia, and the limited impact on public health, the benefits of exposure reduction on health are unclear and thus, the costs of precautionary measures should be very low… Provided that the health, social and economic benefits of electric power are not compromised, implementing very low-cost precautionary procedures to reduce exposure is reasonable and warranted. (*Id.* at p. 372).

Wisconsin, Minnesota, and California have all conducted literature reviews or research to examine this issue. In 2002, Minnesota formed an Interagency Working Group ("Working Group") to evaluate the body of research and develop policy recommendations to protect the public health from any potential problems resulting from HVTL EMF effects. The Working Group consisted of staff from various state agencies and published its findings in a

White Paper on Electric and Magnetic Field (EMF) Policy and Mitigation Options in September 2002, (Minnesota Department of Health, 2002). The report summarized the findings of the Working Group as follows:

> Research on the health effects of [MF] has been carried out since the 1970s. Epidemiological studies have mixed results – some have shown no statistically significant association between exposure to [MF] and health effects, some have shown a weak association. More recently, laboratory studies have failed to show such an association, or to establish a biological mechanism for how magnetic fields may cause cancer. A number of scientific panels convened by national and international health agencies and the United States Congress have reviewed the research carried out to date. Most researchers concluded that there is insufficient evidence to prove an association between [MF] and health effects; however, many of them also concluded that there is insufficient evidence to prove that [MF] exposure is safe. (*Id.* at p. 1.)

The Public Service Commission of Wisconsin ("PSCW") has periodically reviewed the science on MFs since 1989 and held hearings to consider the topic of MF and human health effects. The most recent hearings on MF were held in July 1998. In January 2008, the PSC published a fact sheet regarding MFs. In this fact sheet the PSC noted that:

> Many scientists believe the potential for health risks for exposure to [MFs] is very small. This is supported, in part, by weak epidemiological evidence and the lack of a plausible biological mechanism that explains how exposure to [MFs] could cause disease. The [MFs] produced by electricity are weak and do not have enough energy to break chemical bonds or to cause mutations in DNA. Without a mechanism, scientists have no idea what kind of exposure, if any, might be harmful. In addition, whole animal studies investigating long-term exposure to power frequency [MF] have shown no connection between exposure and cancer of any kind. (PSC, 2008).

The Commission, based on the Working Group and World Health Organization findings, has repeatedly found that "there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects." *In the Matter of the Application of Xcel Energy for a Route Permit for the Lake Yankton to Marshall Transmission Line Project in Lyon County*, Docket No. E-002/TL-07-1407, Findings of Fact, Conclusions of Law and Order Issuing a Route Permit to Xcel Energy for the Lake Yankton to Marshall Transmission Project at p. 7-8 (Aug. 29, 2008); *See also*, *In the Matter of the Application for a HVTL Route Permit for the Tower Transmission Line Project*, Docket No. ET-2, E015/TL-06-1624, Findings of Fact, Conclusions of Law and Order Issuing a Route Permit to Minnesota Power and Great River Energy for the Tower Transmission Line Project and Associated Facilities at p. 23 (Aug. 1, 2007)("Currently, there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects.").

The Commission again confirmed its conclusion regarding health effects and MFs in the Brookings County – Hampton 345 kV Route Permit proceeding ("Brookings Project"). In the Brookings Project Route Permit proceeding, Applicants Great River Energy and Xcel Energy and one of the intervening parties provided expert evidence on the potential impacts of electric and magnetic fields on human health. The Administrative Law Judge in that proceeding evaluated written submissions and a day-and-half of testimony from these two expert witnesses. The Administrative Law Judge concluded: "there is no demonstrated impact on human health and safety that is not adequately addressed by the existing State standards for [EF or MF] exposure." *In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota*, Docket No. ET-2/TL-08-1474, ALJ Findings of Fact, Conclusions and Recommendation at Finding 216 (April 22, 2010 and amended April 30, 2010).

The Commission adopted this finding on July 15, 2010. *In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota*, Docket No. ET-2/TL-08- 1474, Order Granting Route Permit (September 14, 2010).

6.6 Stray Voltage

"Stray voltage" is a condition that can occur on the electric service entrances to structures from distribution lines, not transmission lines. More precisely, stray voltage is a voltage that exists between the neutral wire of the service entrance and grounded objects in buildings such as barns and milking parlors.

Transmission lines do not, by themselves, create stray voltage because they do not connect to businesses or residences. Transmission lines, however, can induce stray voltage on a distribution circuit that is parallel to and immediately under the transmission line. Stray voltage issues are not anticipated for the Project.

If stray voltage issues arise as a result of the construction of the Project, the Project will take appropriate measures to address potential stray voltage issues on a case-by-case basis.

6.7 Vehicle Use and Metal Buildings Near Power Lines

Passenger vehicles and trucks may be safely used under and near power lines. Due to the location of these lines, there will be minimal vehicle traffic near the lines. However, as with all power lines built by the Company, these lines will be designed to meet or exceed minimum clearance requirements with respect to roads, driveways, cultivated fields and grazing lands specified by the NESC. Recommended clearances within the NESC are designed to accommodate a relative vehicle height of 14 feet.

Buildings are permitted near transmission lines but are generally discouraged within the right-of-way itself because a structure under a line may interfere with safe operation of the transmission facilities. Due to the location of the lines, we do not anticipate any buildings other than the Plant will be located near the transmission lines.

6.8 Radio and Television Interference

This subsection addresses the requirements of Minnesota Rule 7849.0330(A)(4) that states an applicant shall provide:

"a discussion of radio and television interference attributable to the transmission facility;"

The Project is not expected to cause radio and television interference. Corona from transmission line conductors can generate electromagnetic "noise" at

the same frequencies that radio and television signals are transmitted. This noise can cause interference with the reception of these signals depending on the frequency and strength of the radio and television signal. Tightening loose hardware on the transmission line usually resolves the problem.

If radio interference from transmission line corona does occur, satisfactory reception from AM radio stations previously providing good reception can be restored by appropriate modification of (or addition to) the receiving antenna system. AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly within the right-of-way to either side.

FM radio receivers usually do not pick up interference from transmission lines because corona-generated radio frequency noise currents decrease in magnitude with increasing frequency and are quite small in the FM broadcast band (88-108 Megahertz) and the excellent interference rejection properties inherent in FM radio systems make them virtually immune to amplitude type disturbances.

A two-way mobile radio located immediately adjacent to and behind a large metallic structure (such as a steel tower) may experience interference because of signal-blocking effects. Movement of either mobile unit so that the metallic structure is not immediately between the two units should restore communications. This would generally require a movement of less than 50 feet by the mobile unit adjacent to a metallic tower.

Television interference is rare but may occur when a large transmission structure is aligned between the receiver and a weak distant signal, creating a shadow effect. Loose and/or damaged hardware may also cause television interference. If television or radio interference is caused by or from the operation of the proposed facilities in those areas where good reception is presently obtained, the Company will inspect and repair any loose or damaged hardware in the transmission line, or take other necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if deemed necessary.

6.9 Land Requirements

This subsection addresses the requirements of Minnesota Rule 7849.0320(A) that states an applicant shall provide:

"the estimated range of land requirements for the facility with a discussion of assumptions on land requirements for water storage, cooling systems, and solid waste storage;"

Total land area required for the Project, including the cooling tower, substation and transmission interconnection is approximately 35 acres (see Figure 5-3). The Project will be entirely on land already used for electric power production. Most of the site will be protected to the 100 year flood elevation level and additional protection will be provided by final grades and equipment elevations. Although protected, the area has a floodplain designation which will be addressed in the Site Permit application based on previous modeling (HEC/RAZ) work. The Black Dog Repowering Project and new switch yard will be located in areas at the Plant site currently used for coal storage and ash ponds. The proposed transmission line taps will be located on either side of the existing Xcel Energy railroad spur and service road that enters into the Black Dog Plant from the south. The transmission lines will then turn east following the north shoreline of Black Dog Lake into the new Project substation.

On site water storage will include three tanks for storage of raw and treated water for use in the HRSG's, evaporative cooling and other processes. Aqueous ammonia storage tank(s) will be added to the site for air emission NO_x reduction. No solid waste will be permanently stored on site. Temporary storage of minor quantities of oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, industrial wastes, universal wastes and hazardous wastes will occur during operation of the Project. As is the case with other similar facilities, the Project is expected to be a very small quantity generator ("VSQG") of hazardous waste.

6.10 Vegetation and Wildlife

The Project is located within the Minnesota and Northeast Iowa Morainal Section (222M), a section within the biogeographic province known as the Eastern Broadleaf Forest Province under the Ecological Classification System ("ECS") developed by the MnDNR and the U.S. Forest Service (MnDNR, 2009). The Project is further located on the border of the Anoka Sand Plain and the St. Paul Baldwin Plains and Moraines subsections of the Minnesota and Northeast Iowa Morainal Section. The Project site is primarily surrounded by wetland and riparian habitat and provides habitat for many species of plants and animals.

6.10.1 Wildlife

Wildlife commonly found near the Plant site includes a variety of small to medium sized mammals, reptiles and amphibians, birds, and fish. The largest mammal typically found in the area is the white-tailed deer. Other mammals include coyotes, fox, raccoons, beaver, opossum, woodchucks, squirrels, and muskrats. Reptiles near the Plant site include Snapping turtles, Map turtles, Softshell turtles, Painted turtles, gopher snakes, fox snakes, and northern water snakes. Amphibians include leopard frogs, pickerel frogs, spring peeper, and American toads. Fish species vary depending on the type of water body. The most commonly distributed fish species in the area include largemouth bass, sunfish, crappies, northern pike and multiple species of rough fish such as carp and suckers. Bird species include eagles, turkeys, hawks, pheasants, ducks, herons, and multiple species of song birds.

Because the Plant is located within an urban area, the fauna generally present are adapted to high levels of anthropogenic disturbance. Further, the existing Black Dog Plant provides little to no habitat for wildlife species. Therefore, it is unlikely that the construction, operation, and maintenance of the Project would have an effect on fauna present in the area. Wildlife that inhabit trees that may be removed for the transmission lines will likely be temporarily displaced. Comparable habitat is near the route, and it is likely that these organisms would only be displaced a short distance.

Raptors, waterfowl, and other bird species may be affected by the construction and placement of the transmission lines. Avian collisions are a possibility after the completion of the transmission line in areas where there are wetlands and open water. The nearest open water is Black Dog Lake, which is part of the overall Plant site.

Additionally, the electrocution of large birds, such as raptors, can be a concern with transmission lines. Electrocution occurs when birds with large wingspans come in contact with two conductors or a conductor and a grounding device. The conductors on the proposed transmission lines will be designed to be located in a horizontal configuration instead of a vertical configuration. This design will help mitigate potential avian collisions with the conductors. Additional mitigation measures will be designed in the placement of the transmission lines. Instead of crossing Black Dog Lake directly south of the proposed substation, the lines will be placed along the road between

the protective cover of trees. Swan Flight Diverters ("SFDs") will be placed on the overhead static lines of the transmission line.

6.10.2 Vegetation Cover

Historically, this area was primarily floodplain and terrace forests of silver maple, cottonwood, box-elder, green ash and elm within and along the terrace forests river valley (MnDNR, 2011). Wetland complexes associated with the Minnesota River Valley system are present throughout the area. Many of the native species remain although many wetlands are dominated by invasive species such as reed canary grass or purple loose-strife.

Because the Project will be constructed within the existing Plant footprint and adjacent to an existing, active railroad line, as well as within an area populated by transmission lines and structures, the Project impacts to vegetation will be minor. The only impact will be a number of trees that will be removed along the proposed transmission line route.

6.10.3 Threatened and Endangered Species

U.S. Fish and Wildlife Service

The U.S. Fish and Wildlife Service's ("FWS's") website was reviewed for a list of species covered under the Endangered Species Act ("ESA") that may be present within Dakota County. According to the website, the following two federally listed species are known to occur within the county: Higgins eye pearlymussel (*Lampsilis higginsii*) and prairie bush-clover (*Lespedeza leptostachya*).

The Higgins eye pearlymussel is listed as endangered and occurs only within the Mississippi River and the lower portion of some of its larger tributaries. The Project will not be located at the Mississippi River. Therefore, it was determined that the Project will have no effect on the Higgins eye pearly mussel or its habitats.

The prairie bush-clover is listed as threatened and occurs within native dry mesic-prairies where the soils are well-drained with high sand or gravel content. The Project is confined to an existing Plant site and along an existing active railroad corridor that is surrounded by a very large wetland complex where only poorly-drained soils exist. Therefore, it has been determined the Project will have no effect on the prairie bush-clover or its habitat.

State of Minnesota
A request for a MnDNR Natural Heritage Information System ("NHIS") search and comments regarding rare species and natural communities for the Project Area was submitted to the MnDNR on January 11, 2011. The MnDNR responded in a letter dated March 8, 2011. The results of the MnDNR Natural Heritage Database search and MnDNR response letter are included in Appendix F.

6.11 Human Settlement

In prehistoric and the early historic periods, the bluffs above the river were the preferred location for settlement. Human groups utilized the resources in the bottomlands and wetlands, but they did not spend significant time or routinely leave behind evidence of their presence there (Merjent, Inc. 2010. Phase 1a Literature Review for the Xcel Energy Proposed Black Dog Repower Project, Dakota County, Minnesota. December 30, 2010). Today, the study area is almost entirely limited to industrial infrastructure.

The closest structure to the proposed transmission line's termination and connection with the existing 345 kV transmission lines is a residence 750 feet south of this point.

According to U.S. Census Bureau data and as shown in Table 6-7, minority groups in the area constitute only a small percentage of the total population, averaging 11.8%. Per capita incomes within the county and nearest cities to the Plant site are higher than the State of Minnesota. The percentage of persons living below the poverty level in the area is approximately 50% less than the State average. The area does not contain disproportionately high minority populations, low-income populations, or high percentages of persons living below the poverty level.

Table 6-7: Population and Economic Characteristics

Location	Population	Minority Population (Percent)	Caucasian Population (Percent)	Per Capita Income	Percentage of Individuals Below Poverty Level
State of Minnesota	5,303,925[a] (2010)	11.4 (2009)[b]	88.6 (2009)[b]	$23,198 (1999)[b]	9.6 (2008)[b]
Dakota County [c]	396,500 (2009)	11.4 (2009)	88.6 (2009)	$27,008 (1999)	4.6 (2008)
City of Burnsville	59,135 (2009)[d]	12.5 (2000)[e]	87.5 (2000)[e]	$27,098 (1999)[e]	5.1 (1999)[e]
City of Eagan	64,186 (2009)[f]	12.0 (2000)[g]	88.0 (2000)[g]	$30,167 (1999)[g]	2.9 (1999)[g]

Sources:

[a] U.S. Census Bureau. 2010 U.S. Census, Resident Population Data, Population Density. http://2010.census.gov/2010census/data/apportionment-dens-text.php

[b] U.S. Census Bureau. State and County QuickFacts. Minnesota. Available online at http://quickfacts.census.gov/qfd/states/27000.html. Accessed December 2010.

[c] U.S. Census Bureau. State and County QuickFacts. Dakota County, Minnesota. Available online at http://quickfacts.census.gov/qfd/states/27/27037.html. Accessed December 2010.

[e] U.S. Census Bureau. State and County QuickFacts. City of Burnsville. Available online at http://quickfacts.census.gov/qfd/states/27/2708794.html. Accessed December 2010.

[d] U.S. Census Bureau. Population Finder. Burnsville City, Minnesota. Available online at http://factfinder.census.gov/servlet/SAFFPopulation?_event=Search&geo_id=05000US27037&_geoContext=01000US%7C04000US27%7C05000US27037&_street=&_county=Burnsville&_cityTown=Burnsville&_state=04000US27&_zip=&_lang=en&_sse=on&ActiveGeoDiv=geoSelect&_useEV=&pctxt=fph&pgsl=050&_submenuId=population_0&ds_name=null&_ci_nbr=null&qr_name=null&reg=null%3Anull&_keyword=&_industry=. Accessed December 2010.

[f] U.S. Census Bureau. Population Finder. Eagan City, Minnesota. Available online at http://factfinder.census.gov/servlet/SAFFPopulation?_event=Search&geo_id=16000US2708794&_geoContext=01000US%7C04000US27%7C16000US2708794&_street=&_county=Eagan&_cityTown=Eagan&_state=04000US27&_zip=&_lang=en&_sse=on&ActiveGeoDiv=geoSelect&_useEV=&pctxt=fph&pgsl=160&_submenuId=population_0&ds_name=null&_ci_nbr=null&qr_name=null&reg=null%3Anull&_keyword=&_industry=. Accessed December 2010.

[g] U.S. Census Bureau. State and County QuickFacts. City of Eagan. Available online at http://quickfacts.census.gov/qfd/states/27/2717288.html. Accessed December 2010.

The Project is not located in an agricultural area. Based on recent aerial photographs, the nearest significant tracts of land with evidence of agriculture are south of the City of Apple Valley, approximately 6 miles from the Project.

There are no forested areas where species are harvested within the Plant boundaries. The primary tree cover in the area is associated with waterways and along the Xcel Energy railroad spur. No economically significant forestry resources are located along the proposed new transmission lines route.

The Minneapolis – St. Paul International Airport ("MSP") is located approximately 3.3 miles north of the property boundaries. According to the Standards for Determining Obstructions, proposed structures within the three

mile radius of an airfield cannot exceed 200 feet in height. The proposed transmission lines will not be located within three linear miles of the MSP and are therefore not subject to Federal Aviation Administration ("FAA") requirements defining airfield obstructions (14 C.F.R. 77).

According to the Minnesota Department of Transportation, county pit map for Dakota County and USGS topographic maps, there are no gravel pits, rock quarries, or commercial aggregate sources in the vicinity of the Plant boundaries.
http://www.dot.state.mn.us/materials/maps/copitmaps/dakota.pdf.
Because no existing gravel and rock resources are being utilized within the area, no impacts are anticipated. Unknown resources that may exist in the area would be situated in close proximity to existing utility and roadway rights-of-way, making development unlikely.

6.12 Archeological and Historic Resources

In December 2010, a review of records at the Minnesota State Historic Preservation Office ("SHPO") identified two archaeological sites and one inventoried historic architectural property located within one mile of the Plant site. A summary of the inventoried cultural resource sites is provided in Table 6-8.

Table 6-8: Previously Identified Historic Properties Near the Plant Site

Type of Historic Property	Inventory Number	Description	NRHP Status
Archaeological	21HE0012	Contact Period mound site	unevaluated
Archaeological	21DK0041	Prehistoric Arvilla Complex mound site (destroyed)	N/A
Architectural	N/A	Union Pacific Railroad	Potentially eligible

Both of the archaeological sites are mound sites, confirmed as burials by excavation. Site 21DK0041, which was dated to the prehistoric Arvilla Complex (AD 500-900), was completely destroyed by development in the 1960s. Site 21HE0012 was first recorded in the 1890s as a mound site containing 36 mounds. In the 1930s a University of Minnesota student excavated Mound 21 of the site and discovered historic burials dating to the

well documented period of Dakota occupation of the Minnesota River Valley. The current condition of this site is unknown. As an unplatted burial, this site is subject to the Minnesota Private Cemeteries Act (Minnesota Statutes Chapter 307), and comes under the jurisdiction of the Office of the State Archaeologist. As a Native American burial ground, the site would also come under the jurisdiction of the Minnesota Indian Affairs Council.

Site 21DK0041 has been destroyed. Site 21HE0012 is located on the river bluff more than one-half mile north of the Plant boundaries. Since both sites are located outside the construction footprint and outside the 150-feet-wide transmission line rights-of-way, they will not experience direct impacts resulting from the construction of this Project.

The only historic architectural property within one mile of the Plant boundaries is the Union Pacific Railroad, which runs along the southern edge of the Minnesota River Valley. This rail line between St. Paul and Mankato, first built in 1864, represents the early expansion of Minnesota and the transportation network that helped bring the state's agricultural products to the marketplace. A Multiple Property Nomination to the NRHP for Railroads in Minnesota 1862-56 (Schmidt et al., 2002) establishes the criteria for NRHP eligibility for railroad properties. Although the Union Pacific Railroad is not specified as eligible for listing on the NRHP, it does meet the criteria and should be considered potentially eligible.

The Union Pacific Railroad is on the southern edge of the transmission line construction footprint, but will not be directly impacted by proposed construction. Further, the Project will be constructed within the existing plant boundaries and the transmission line construction will occur along an artificial berm built to support the railroad spur from the Union Pacific line to the Plant. The proposed construction is in keeping with the industrial use and development of the location. The proposed construction will constitute an in-kind expansion of the existing built environment and will not create new indirect visual impacts.

On behalf of Xcel Energy, Merjent, Inc. provided a copy of the Phase 1a literature review report discussing its findings and recommendation that no archaeological or historic resources would be affected by construction or operation of the new facility and transmission lines on January 15, 2011. In its letter dated February 15, 2011, the Minnesota SHPO concluded that, based on its review of the Project information, there are no properties listed on the State

or NRHP and no known or suspected archaeological properties in the area that would be affected by the Project (see Appendix G).

6.13 Traffic and Transportation Infrastructure

This subsection addresses the requirements of Minnesota Rule 7849.0320(B) that states an applicant shall provide:

"the estimated amount of vehicular, rail, and barge traffic generated by construction and operation of the facility;"

During construction of the Project, there will be an increase in traffic on the roadways into the Plant. Site fill activities will require approximately 30,000 trucks for delivery of material. Minor temporary road upgrades may be necessary to facilitate delivery of equipment and materials for the Project. Some equipment and materials for construction of the Project will be delivered by rail. During construction, barge delivery is also an option but is not anticipated to be significant. Operation of the Project will result in a decrease in traffic from current traffic levels. The existing roads and rail yard will meet the Project access needs during future operations. The delivery of coal to the Plant, which has historical been by rail, will cease as a result of the Project.

6.14 Work Force Requirements

This subsection addresses the requirements of Minnesota Rule 7849.0320(J) which required an applicant to provide:

"the estimated work force required for construction and operation of the facility;"

An estimated 300 construction jobs will be created during the equipment installation phase of the Project, adding over $30 million of payroll into the economy. Operation of the repowered units after the Project construction will require approximately 15 full-time positions.

7 Project Benefits Society

This Project benefits society by allowing the Company to meet our customers' energy needs in an economically and environmentally responsible manner, thereby supporting future development in Minnesota and the region.

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minn. R. 7849.0120). This section addresses the third criterion which states that:

"by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a matter compatible with protecting the natural and socioeconomic environments, including human health."

7.1 Society Benefits from Reliable and Low Cost Electricity Sources

Minnesota law establishes parameters to ensure that utilities select and implement resources that provide reliable energy at reasonable prices and with minimal impact on the environment. Our peak demand and energy requirements are growing at an average of 1.1% and 0.9%, respectively per year.[6] We have a statutory obligation under Minnesota Statutes Section 216B.04 to plan our system to reliably serve our customers.

A cost effective, reliable energy supply is an economic driver for our customers as well as state and regional economies. Our diverse energy portfolio provides customers with a reliable and economical electrical energy supply. This Project will complement our electric generation resources by providing needed intermediate and peaking capacity and utilizes existing facilities to provide reliable, cost effective energy to meet our customers' needs in a more environmentally sound manner.

We will be adding significant amounts of additional wind generation to our system to meet the renewable targets of the jurisdictions in which we operate. The addition of wind resources requires other resources that can ramp quickly to meet customers' needs when the wind resources are unavailable due to the lack of appropriate wind speeds. Having quick ramp rate resources will help

[6] These estimates are based on 50 percentile energy forecast and 90 percentile net demand forecast.

the Company better integrate wind generation into our system due to the variability in wind generation.

This Project also increases system reliability due to its close proximity to a large load center, the Twin Cities Metropolitan area. This Project provides additional capacity close to load that can economically generate more energy for the load center with less energy lost during transmission.

The Project also adds a basically new natural gas resource to our generation portfolio. Natural gas-fired generation is among the most reliable technologies to meet intermediate and peaking needs. While natural gas based generating capacity is increased, actual use of natural gas to produce electric energy increases only modestly. The addition of the Project allows us to better utilize base load resources elsewhere on the system.

7.2 Provides Value to Customers

This Project is a cost-effective means of providing needed capacity on short notice. The Project increases system efficiencies by being able to meet both increasing intermediate and peaking needs at an existing generation facility site. The use of an existing Plant site also allows for better utilization of existing off-site transmission infrastructure. This Project is a cost-effective, lower GHG emitting resource than alternatives. Additionally, this Project helps offset the intermittency of the significant amount of new wind resources that are being added to our system. Lastly, the Project provides a hedge against future environmental regulations. Considered together, this cost-effective lower emissions resource provides great value – economic and environmental – to customers.

7.3 Efficiently Uses Existing Plant Site

This Plant site already contains existing gas-fired generation and the space necessary to add additional gas-fired generation. The site footprint will not be expanded and no greenfields will be affected by the Project. The Project requires only minimum additional transmission facilities to transport electricity from the Plant to the electrical grid. The Project will also take advantage of existing gas pipelines into the Twin Cities area, rail and road transportation, water supply and wastewater infrastructure. It is also possible that some of the new high-pressure gas pipeline can be sited within the current pipeline right of way.

7.4 Best Fit to Existing Transmission Facilities

Only short new transmission line interconnections to the existing metropolitan Twin Cities beltway transmission system are required to accommodate the increase in generating capacity at the Plant site. Based upon preliminary analysis, bulk system reliability is maintained (adequacy and security) without major degradation in transmission system performance, thereby rendering this a highly preferred site. The Black Dog Plant has the transmission rights necessary to deliver the combined output of the Plant to customers.

7.5 Results in Lower Emissions

The Project will generate the least air emissions and the least impact to air quality of all feasible alternatives to meet the Project objectives. The Project will result in significantly less CO_2 being emitted to the atmosphere as compared to the alternatives. The specific comparisons of emissions of the alternatives are shown in Table 4-4 and as discussed in Section 4.4.9, demonstrate that the Project has lower air emissions when compared directly to alternatives.

7.6 Creates Jobs

The Project will employ an estimated 300 construction workers over the Project construction period. These high-skilled, high-paying positions will add payroll dollars into the local economy. When complete, the Project will employ a highly skilled and dedicated work force to operate and maintain the new units. This work force not only benefits the Plant but also the entire community as active, involved, tax paying citizens participating and contributing to the greater social fabric of the community.

7.7 Supports Future Economic Development

Historically, we have maintained low electric rates relative to utilities in other regions of the United States. As a result, Minnesota and the region have been able to attract industrial concerns and maintain steady economic growth. This Project will allow us to continue to reliably serve our customers' energy needs while maintaining favorable rates to support future economic development in Minnesota and the surrounding states. The Project was the most cost-

effective alternative—even when a wide variety of sensitivities were considered.

7.8 Provides Tax Benefits

It is anticipated that the Project will continue to provide local, state and federal tax benefits. It is estimated that the local property tax benefits due to the Project will result in an additional $2 million annually.

8 Project Complies with Rules and Policies

This Project serves the overall state energy needs, fosters state energy policy, and complies with all applicable rules and regulations.

A Certificate of Need must be granted to an applicant upon determining that four principal criteria are met (Minn. R. 7849.0120). This section addresses the fourth criterion, which provides that:

"the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments."

8.1 Project is Consistent with Minnesota Energy Policy

8.1.1 Legislative Preference

The Minnesota legislature has determined that:

"The following energy sources for generating electric power distributed in the state, listed in their descending order of preference, based on minimizing long-term negative environmental, social, and economic burdens imposed by the specific energy sources are:

1. *wind and solar;*
2. *biomass and low-head or refurbished hydropower,*
3. *decomposition gases produced by solid waste management facilities, natural gas-fired cogeneration, and waste materials or byproducts combined with natural gas;*
4. *natural gas, hydropower that is not low-head or refurbished hydropower, and solid waste as a direct fuel or refuse-derived fuel; and*
5. *coal and nuclear power."*[7]

Xcel Energy supports an energy policy that balances the impact of energy use and production on the environment with the costs and reliability of various resource options. We believe a diverse portfolio that includes renewable resources and DSM best meets this objective. The selection of this Project

[7] Minn. Stat. § 216C.051, subd. 7(c) and (d).

over the alternatives considered is consistent with the State's Energy Policy priorities.

First, we continue our dedication to achieving high levels of DSM savings. In our most recent Triennial CIP filing, we committed to achieve savings of 1.15% of gross annual retail sales in 2010, 1.2% in 2011, and 1.3% in 2012. We propose to fully implement our 1.3% savings goal, and work toward meeting the state goal of 1.5% savings over the next several years as outlined in the Next Generation Energy Act of 2007. And, in fact our preliminary results for 2010 indicate that we achieved a 1.5% savings goal, or over 400 GWhs in savings.

Second, we are on target to comply with the nation's most aggressive renewable energy standard. If we desire to meet this goal on a levelized basis, we will need to add approximately 100 MW of wind to our system per year for the foreseeable future. As result of our DSM and RES requirements, we did not look at adding additional wind or energy efficiency savings in lieu of a resource.

We compared this project to the following alternatives:

- investing in the life extension and environmental control retrofits necessary to continue to operate Units 3 and 4 on coal,
- ceasing the operation of Units 3 and 4 and constructing about 700 MW of combined cycle generation at the Black Dog Generating Plant site,
- adding necessary resources elsewhere on the Company's system and ceasing the operation of Units 3 and 4, and
- a biomass alternative.

Of these alternatives, the Black Dog Repowering Project is the most cost effective project, results in the greatest system CO_2 emissions reductions of the alternatives, and results in the fewest environmental impacts. The Project involves modification to an existing site to generate lower emission energy and minimizes "*negative environmental, social and economic burdens…*" when compared to the alternatives considered.

The 2007 Legislature declared the state's goal to reduce statewide GHG emissions across all sectors producing those emissions to a level at least 15% below 2005 levels by 2015, to a level at least 30% below 2005 levels by 2025, and to a level at least 80% below 2005 levels by 2050. (Minn. Stat. § 216H.02,

subdivision 1.) The modeling supporting our 2010 Resource Plan, which includes this Project, suggests that implementation of the 2010 Resource Plan will ensure our compliance with the state's GHG reduction milestones, providing a 25% reduction in CO_2 emissions from 2005 levels by 2020.

8.1.2 State Energy Policy

This Project serves the State Energy Policy goals as stated in the Office of Energy Security's publication *Energy Policy and Conservation Report 2008*. The four guiding principles of Minnesota energy policy are to ensure that:

1. *Minnesota has a reliable energy-provision system into the future;*
2. *the state's energy system meets Minnesota's economic needs;*
3. *Minnesota's energy costs are reasonable priced; and*
4. *the environmental impacts of energy produced and consumed in the state are reduced.*

The "continuing reliability and quality of electric service is one of the guiding principles of Minnesota's energy policy and is among the OES's top priorities in the coming years. Accordingly, the OES, in concert with other state agencies and interested persons, seeks to preserve and enhance the reliability and quality of the electric system in Minnesota."[8]

This Project clearly addresses all four of these guiding principles by offering a reliable, reasonably priced, and environmentally friendly generation option to meet our customer's needs. More importantly, because the focus of the OES's priorities is reliability, this Project better meets this emphasis than any of the other alternatives considered. In addition to providing increased system reliability by being able to respond to the fluctuations of wind resources, by being located close to a major load center, this Project also enhances the overall reliability of the transmission system.

8.1.3 Non-Proliferation Policy

This Project will take full advantage of existing infrastructure by being constructed at an existing generation facility and using existing high-voltage electric transmission facilities to transport the energy generated. The use of

[8] Page 17, *Energy Policy and Conservation Report 2008*, Office of Energy Security

existing transmission facilities is consistent with the State of Minnesota's commitment to non-proliferation of transmission corridors.[9]

8.2 The Project Complies with Federal and State Environmental Regulations

The Project meets or exceeds the requirements of all applicable federal and state environmental laws and regulations. Chapter 2 provides a list of permits and approvals the Project must obtain from government entities in support of full compliance.

8.3 Carbon Risk Analysis Compliance

Order Point 16 of the Commission's Order dated July 28, 2006 from our 2004 Resource Plan (Docket No. E002/RP-04-1752), states:

Xcel shall discuss carbon risk analysis strategies in the November 1, 2006 base load certificate of need filing required in paragraph 10, in its next resource plan, in future certificate of need filings, and in other proceedings involving the acquisition of generation resources.

There is significant concern over climate change policy—internationally, nationally and at the state level. The contribution of carbon released during the combustion of fossil fuels for electric generation is often at the forefront of that discussion. There has been a significant amount of discussion regarding the development of a market for trading carbon credits. This, and the potential for the regulation of other emissions, creates a potential regulatory and cost risk when proposing to construct a fossil fuel burning power plant that emits carbon dioxide.

This Project reduces carbon dioxide emissions from those currently found at this site and therefore reduces the cost risk associated with potential future carbon regulation. Additional analysis of risks associated with the Project that are driven by carbon regulation uncertainty is provided in Chapter 3 with sensitivity analyses provided in Chapter 4.

---

[9] *People for Environmental Enlightenment and Responsibility (PEER) v. Minnesota Environmental Quality Council*, 266 N.W. 2d 858 (Minn. 1978)

CERTIFICATE OF SERVICE

I, Mark Suel hereby certify that I have this day served copies of the foregoing document on the attached list of persons electronically, delivery by hand or by causing to be placed in the U.S. mail at Minneapolis, Minnesota.

DOCKET NO. E002/CN-11-184

Dated this 15th day of March, 2011

/s/

Mark Suel

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
James J.	Bertrand	james.bertrand@leonard.com	Leonard Street & Deinard	Suite 2300 150 South Fifth Street Minneapolis, MN 55402	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Steven	Bosacker		City of Minneapolis	City Hall, Room 301M 350 South Fifth Street Minneapolis, MN 554151376	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Christopher	Clark	christopher.b.clark@xcelenergy.com	Xcel Energy	5th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Jeffrey A.	Daugherty	jeffrey-daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Ron	Elwood	relwood@mnlsap.org	Legal Services Advocacy Project	2324 University Ave Ste 101 St. Paul, MN 55114	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 554022859	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
David W.	Niles		Avant Energy Services	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Richard	Savelkoul	rsavelkoul@felhaber.com	Felhaber, Larson, Fenlon & Vogt, P.A.	444 Cedar St Ste 2100 St. Paul, MN 55101-2136	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Byron E.	Starns	byron.starns@leonard.com	Leonard Street and Deinard	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Lisa	Veith		City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_8-1065_CC - SL
Christopher	Clark	christopher.b.clark@xcelenergy.com	Xcel Energy	5th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Paper Service	No	OFF_SL_8-1065_CC - SL
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_8-1065_CC - SL
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_8-1065_CC - SL
John	Lindell	agorud.ecf@state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_8-1065_CC - SL
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	OFF_SL_8-1065_CC - SL
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_8-1065_CC - SL

Appendix A. Peak Demand and Annual Consumption Forecast 7849.0270, Subparts 3, 4,5 (C) and 6

Forecast Methodology

Overall Methological Framework

Xcel Energy prepares its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. The NSP System serves five jurisdictions. Minnesota, North Dakota and South Dakota are served by Northern States Power Company. Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The overall methodological framework is "model oriented". The NSP and NSPW Systems operate as an integrated system. The forecast is referred to as the 2010 IRP Forecast (August 2010).

Specific Analytical Techniques

1. Econometric Analysis. Xcel Energy uses econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors:
    a. Residential without Space Heating;
    b. Residential with Space Heating;
    c. Small Commercial and Industrial;
    d. Large Commercial and Industrial.

    Xcel Energy also uses econometric analysis to develop the total system MW demand forecast.
2. Trend analysis is used for the "Other" sectors, which includes Public Street and Highway Lighting, Other Sales to Public Authorities, Interdepartmental sales, and Municipals (firm Wholesale).
3. Loss Factor Methodology. Loss factors by legal entity are used to convert the sales forecasts into system energy requirements (at the generator).
4. Judgment. Judgment is inherent to the development of any forecast. Whenever possible, Xcel Energy uses quantitative models to structure its judgment in the forecasting process.

The sales forecasts are estimates of MWh levels measured at the customer meter. They do not include line or other losses. The various jurisdictional class forecasts are summed to yield the total system sales forecast. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy creates native energy requirements based on the sales

forecasts. A system loss factor for each legal entity, developed based on average historical losses, is applied to the jurisdictional sales forecast to calculate total losses. The sum of the jurisdictional MWh sales and losses equals native energy requirements. The native energy requirements, along with peak producing weather and binary variables, are then used as independent variables within an econometric model to forecast Mw peak demand for the Xcel Energy North System.

Models Used

1. Residential Econometric Models. Sales to the residential sectors represent 28.2% of its total NSP System electric sales in 2009. Residential sales are divided into with space heating and without space heating customer classes for each jurisdiction. Ordinary Least Squares models using historical data are developed for each residential sector. A variety of independent variables are used in the models, including:
    - Number of customers;
    - Gross Metro Product for respective jurisdiction;
    - Actual heating and temperature humidity index (THI) degree days;
    - Number of monthly billing days.
2. Small Commercial and Industrial Econometric Models. The small commercial and industrial sector represents 42.2% of NSP System electric sales in 2009. The models are ordinary least squares regressions using historical data. The models include a combination of variables, including the following:
    - Number of small commercial and industrial customers;
    - Gross Metro Product for respective jurisdiction;
    - Employment for respective jurisdiction;
    - Actual heating and temperature humidity index (THI) degree days;
3. Large Commercial and Industrial Econometric Models. Sales to the large commercial and industrial sector represent 25.9 % of NSP System electric sales in 2009. The models are OLS regressions using historical data and a combination of variables, including the following:
    - Industrial Production for respective jurisdiction;
    - Employment for respective jurisdiction;
    - Number of monthly billing days;
    - Indicator variables such as CI reclassification.
4. Others. Sales to the "Others" sector represent 0.7 % of NSP System electric sales in 2009. This sector includes Public Street and Highway

Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Because this class represents a very small portion of the total sales, trend analysis is used and very little growth is forecast.

5. Municipals. Sales to the Municipal utility sector represent 3.0 % of NSP System electric sales in 2009. The municipal class is forecast using separate trend analysis at the individual customer level for NSP and NSPW. The forecast of these municipal customers only includes firm wholesale customer usage.
6. Peak Demand Model. An econometric model is developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including the following:
    - Weather normalized native energy requirements
    - Peak producing weather by month
    - Binary variables

Methodology Strengths and Weaknesses

The strength of the process Xcel Energy uses for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how the NSP System is growing, thereby providing better information for decisions to be made in the areas of generation, transmission, marketing, conservation, and load management.

With respect to accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk that accompanies long-term forecasts. They must also develop plans that are robust over a wide range of future outcomes.

Data Definitions

The following is a list of definitions of the variables considered in Xcel Energy's econometric models.

Jurisdiction Abbreviations

M or MN State of Minnesota

N or ND	State of North Dakota
S or SD	State of South Dakota
W or WI	State of Wisconsin
Mi or MI	State of Michigan

Monthly MWh Sales Series

SLSReswo(Juris)	Residential without space heating for given jurisdiction
SLSResSH(Juris)	Residential with space heating for given jurisdiction
SLSSmCI(Juris)	Small commercial and industrial for given jurisdiction
SLSLgCI(Juris)	Large commercial and industrial for given jurisdiction

Monthly Customer Series

CustReswo(Juris)	Residential without space heating for given jurisdiction
CustResSH(Juris)	Residential with space heating for given jurisdiction
CustSmCI(Juris)	Small commercial and industrial for given jurisdiction
CustLgCI(Juris)	Large commercial and industrial for given jurisdiction

Monthly Economic and Demographic Series

(Juris)HH	Number of Households in given jurisdiction
GMP(MSA)	Gross Metro Product for given metropolitan statistical area
GSP(State)	Gross State Product for given state
EE_(Juris)	Total employment in given jurisdiction
EEGOV_(Juris)	Total Government employment in given jurisdiction
IPMFG_(Juris)	Industrial Production Index - manufacturing in given jurisdiction
IPSB0004_US	Industrial Production – United States
CYPNR_(Juris)	Real per capita Personal Income in given jurisdiction
(Juris)TotRes_RAP	Real Average Price for electric sales to residential customers

Monthly Data Variables used in Demand Model

THI12(Month)Cust Temperature Humidity Index @12:00 noon multiplied by total retail customers

THI12_LAG1(Month)Cust Temperature Humidity Index @12:00 noon on the day before the peak day multiplied by total retail customers.

THI15(Month)Cust Temperature Humidity Index @15:00 (3:00 PM) on the peak day multiplied by total retail customers

HDD(Season) Normal Heating Degree Days on the day of the Peak multiplied by a binary variable for the season (winter – Wtr, shoulder month – sh)

AvgTemp_Cust Average Temperature on the peak day multiplied by total retail customers

DaysOver90(Month) cumulative days over 90 for the calendar year as of the monthly peak day

WNActEnergy_LpYrAdj_12MoSum 12 month rolling sum of the weather normalized net energy requirements adjusted to remove the effect of leap years

MfgSlowdown An index based on Industrial (Manufacturing) Production and Manufacturing Employment

Monthly Weather Variables

H65_bill (Juris) (Month) HDD base 65 for given jurisdiction and month

T65_bill (Juris) (Month) THI DD base 65 for given jurisdiction and month

Other Monthly Variables

BillDaysCellnet21 Billing Month Days

Monthly Binary Variables

Jan Binary variable for the month of January

Feb Binary variable for the month of February

Mar Binary variable for the month of March

Apr Binary variable for the month of April

May Binary variable for the month of May

Jun Binary variable for the month of June

Jul Binary variable for the month of July

Aug	Binary variable for the month of August
Sep	Binary variable for the month of September
Oct	Binary variable for the month of October
Nov	Binary variable for the month of November
Dec	Binary variable for the month of December

Xcel Energy uses internal and external data to create its MWh sales and Mw peak demand forecast.

Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand.

Through 2007 weather data (dry bulb temperature and dew points) were collected from a respected local meteorologist (Mr. Frank Watson) for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. Beginning in 2008 weather data has been collected from weatherunderground.com for the same locations. The heating degree-days and THI degree-days are calculated internally based on this weather data.

Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from Global Insight, Inc. data banks, and reflect the most recent values of those series at the time of modeling.

Demand-Side Management Programs

The regression model results for the residential and commercial and industrial classes are reduced to account for the expected incremental impacts of demand-side management ("DSM") programs. An annual forecast of the impact of new DSM programs (excluding Saver's Switch) is developed by Xcel Energy's DSM Regulatory Strategy and Planning Department. The impacts are converted by class from calendar month energy to billing month sales volumes. The resulting sales volumes are used to reduce the class level sales forecasts that result from the regression modeling process. Impacts from all program installations through 2009 are assumed to be imbedded in the historical data, so only new program installations are included in the DSM adjustment.

An additional adjustment was made to the current forecast to account for new federally mandated efficiency standards for business cooling. This new

standard supplants DSM programs the Company previously had in place, which reduces the amount of Business DSM. However, the standards have not been in place long enough to be reflected in actual sales data used in the development of the forecast. The solution to this problem was to adjust forecasted Commercial/Industrial sales downward to incorporate the effect of the new standards.

The Company's Saver's Switch program results in short-term interruptions of service designed to reduce system capacity requirements rather than permanent reductions in energy use, so it is not considered here.

Overview of Probability Distributions

Xcel Energy uses a straightforward extension of the peak demand econometric model to assess risk around the expected value of the peak demand by conducting a Monte Carlo simulation on the main drivers of the peak model (weather and native energy requirements). For the Monte Carlo energy probability distribution model, the main drivers are weather and Minnesota Households (HH_MN).

The Monte Carlo stochastic simulation of peak demand (MW) or (energy (MWh)) involves taking 10,000 random draws from the weather probability distributions as well as 10,000 draws from the 12-month sum of energy probability distribution (or HH_MN probability distribution), which, in turn, produces 10,000 forecasts of peak demand (or energy), and thus generates a probability distribution around the mean peak demand (or mean energy).

For example, if the econometric model forecasts that the mean peak demand for 2022 is 10,586 MW, then using the same econometric model, the Monte Carlo simulation method forecasts that there is a 90% probability that the 2022 peak demand will be less than 11,911 MW, or alternatively, a 10% chance that the peak will be less than 9,240 MW.

In summary, the Monte Carlo stochastic simulation method adequately captures the effect of extreme weather on monthly peak demand and month energy usage, while preserving the expected value or mean forecast of peak demand and energy.

Data Adjustments and Assumptions

1. Weather Adjustments. Xcel Energy adjusts the monthly weather data to reflect billing schedules. Therefore, the monthly weather data corresponds exactly with the billing month schedule.

2. Economic Adjustments. All price data and related economic series are deflated to 2000 constant dollars.

Assumptions and Special Information

The data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for the data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and workable one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's median forecast are as follows:

1. Demographic Assumption. Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by Global Insight, Inc., and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.

2. Weather Assumption. Xcel Energy assumes "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 1990-2009. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption that the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.

3. Loss Factor Assumptions. The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses a historical average loss factor for each jurisdiction, and assumes it will not change in the future.

Forecast Coordination

Xcel Energy reports its energy and peak demand forecasts to the Midwest ISO (MISO). MISO then combines the forecasts of all its member utilities. Xcel Energy also reports its forecast to the Public Service Commission of Wisconsin as part of its Strategic Energy Assessment (SEA) process. In this process, the Wisconsin portion of the total Xcel Energy system load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

Forecast Vintage Comparison

As described above, projections of energy and demand are fundamental to identifying the need for generation resources. Thus, these forecasts are an important component in determining the size, type and timing of new generation resources. As a result, ensuring robust forecasts with fully analyzed assumptions and variables is a key component to analyzing a Resource Plan or Certificate of Need.

Forecast Vintage and Comparison

The review process for a Resource Plan or a Certificate of Need typically takes a significant amount of time and effort to complete. During this time, forecasts can change as economic variables change. The graphs below compare the peak demand and energy of the Company's current forecast with the forecasts filed in the 2007 Resource Plan and the Electric Utility Annual Report filed in mid 2010.

Figure 1 indicates that the energy forecast is the same as the forecast reported in our 2010 Annual Electric Utility Report, but lower than the forecast approved in our 2007 Resource Plan. This is due to a reduction in historical volumes and slower growth in some economic indicators since the 2007 Resource Plan forecast was produced.

Figure 1
Net Energy Requirements (MWh)
Median (50th Percentile) Forecast
Comparison of Current and Previous Energy Forecasts

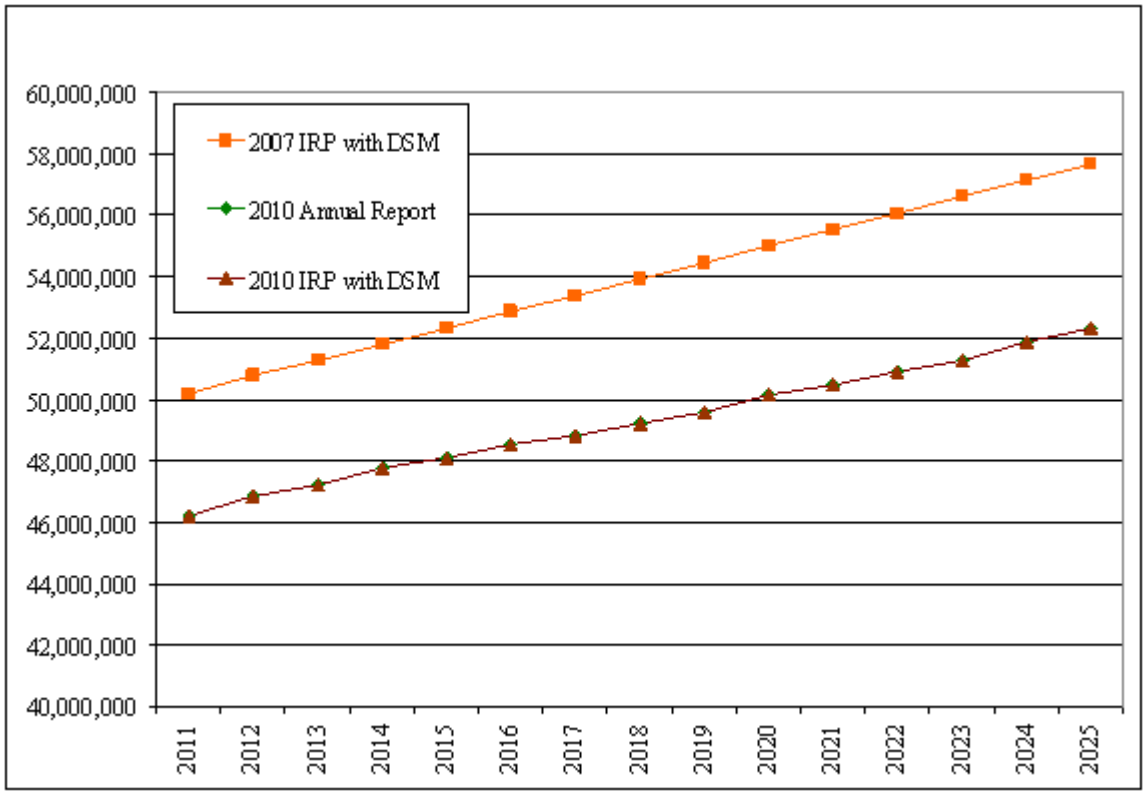
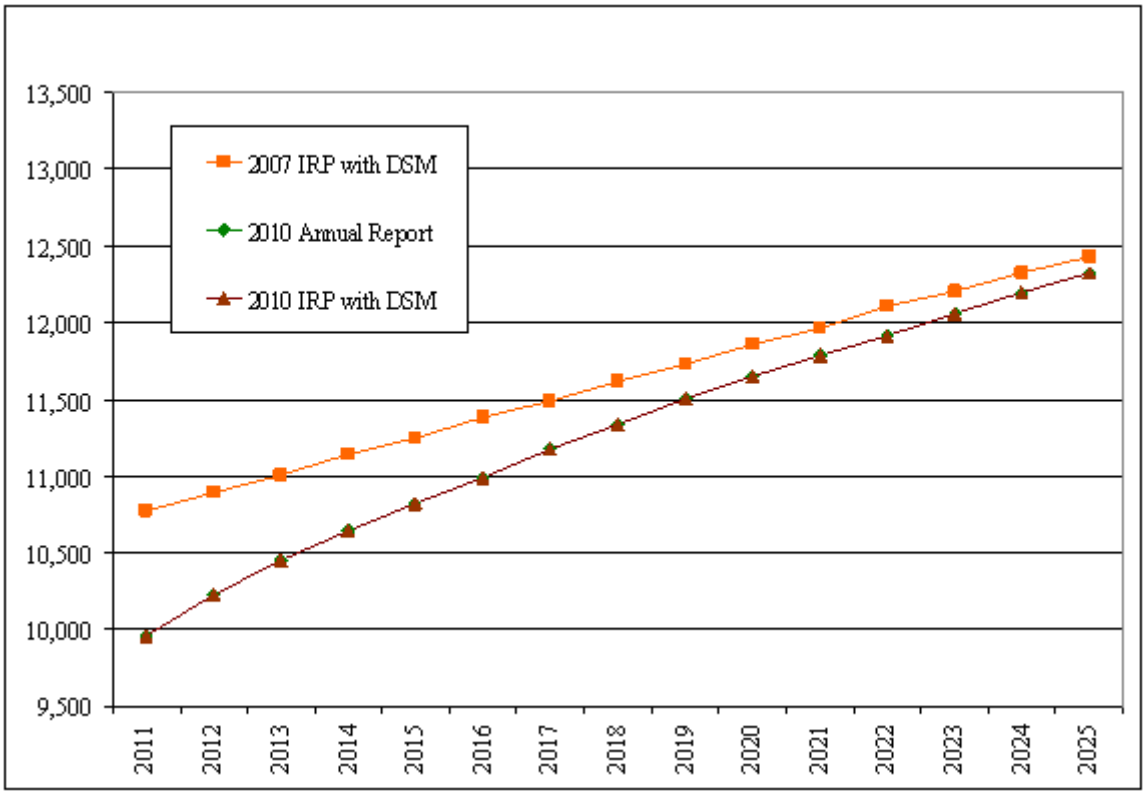


Figure 2 shows a comparison of the 90% peak demand forecasts between 2007 and 2010. While we used a 90% demand forecast in our last Resource Plan, we now use a 50% forecast pursuant to our requirements in the MISO Planning Reserve Sharing Group. However, a comparison of the 90% forecasts is supplied here to provide a visual context for the differences in the two forecasts. Similar to the energy forecast, the 2010 Demand Forecast starts from a much lower level than in 2007. However, the growth rate in 2010 is slightly higher, which is a product of the lower peak demand savings we expect to get from our DSM programs.

Figure 2
Base Peak Demand (MW)
90th Percentile Forecast
Comparison of Current and Previous Demand Forecasts



	MWh Total NSP System ANNUAL Summary:																
	Residential w/o Sp Heat	Residential w/ Sp Heat	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept	Total Other	Total Retail	Wholesale	Total Mwh	Company Use	Retail Losses	Wholesale Losses	Native Requirements
2001	10,087,517	928,706	11,016,223	15,716,290	11,735,057	27,451,347	176,470	129,029	15,746	321,245	38,788,815	714,660	39,503,475	49,924			42,829,758
2002	10,689,123	967,706	11,656,830	14,794,020	12,870,013	27,664,034	177,553	122,059	13,894	313,505	39,634,368	809,058	40,443,427	45,280			43,780,084
2003	10,680,301	981,766	11,662,067	16,579,354	11,443,959	28,023,313	177,054	127,745	16,525	321,323	40,006,704	809,894	40,816,598	47,504	2,828,109	41,190	43,733,401
2004	10,459,500	942,528	11,402,028	16,644,896	11,708,988	28,353,884	188,087	116,072	18,481	322,640	40,078,552	963,618	41,042,169	44,388	2,909,912	58,979	44,055,448
2005	11,169,742	935,853	12,105,594	18,272,282	11,110,675	29,382,957	184,643	118,715	8,511	311,869	41,800,420	1,176,285	42,976,705	55,973	2,907,755	67,711	46,008,144
2006	11,236,540	910,638	12,147,178	18,276,180	11,354,870	29,631,050	192,808	116,475	8,661	317,944	42,096,172	1,526,496	43,622,668	38,748	3,036,721	83,184	46,781,321
2007	11,835,008	656,244	12,491,252	18,492,190	11,724,807	30,216,998	185,376	113,206	14,540	313,122	43,021,372	1,538,399	44,559,771	46,615	3,261,034	83,838	47,951,259
2008	11,363,669	673,452	12,037,121	18,464,532	11,772,762	30,237,294	185,966	103,132	9,174	298,273	42,572,688	1,504,301	44,076,989	45,796	2,940,544	81,605	47,144,934
2009	11,111,576	672,022	11,783,599	18,052,021	10,772,546	28,824,567	189,836	103,092	10,828	303,756	40,911,922	1,251,121	42,163,043	43,809	2,946,738	70,757	45,224,347
2010	11,536,378	676,799	12,213,177	18,237,693	10,890,367	29,128,060	189,596	101,762	10,987	302,345	41,643,581	841,958	42,485,539	46,456	3,065,167	52,545	45,649,707
2011	11,688,723	676,807	12,365,530	18,345,045	11,182,809	29,527,854	192,214	98,677	10,987	301,878	42,195,262	795,123	42,990,385	46,456	3,103,780	50,665	46,191,286
2012	11,834,129	679,268	12,513,397	18,490,623	11,476,322	29,966,946	194,373	98,199	10,987	303,559	42,783,901	795,491	43,579,392	46,456	3,147,287	50,680	46,823,815
2013	11,880,849	678,366	12,559,215	18,569,576	11,719,520	30,289,097	196,548	98,474	10,987	306,009	43,154,321	787,347	43,941,668	46,456	3,175,214	50,353	47,213,690
2014	11,972,825	681,205	12,654,030	18,692,249	12,005,876	30,698,125	198,644	97,410	10,987	307,041	43,659,196	787,705	44,446,901	46,456	3,213,272	50,367	47,756,996
2015	12,057,707	679,865	12,737,572	18,735,189	12,175,434	30,910,624	200,683	96,398	10,987	308,068	43,956,264	788,067	44,744,330	46,456	3,235,502	50,382	48,076,670
2016	12,215,355	683,037	12,898,392	18,835,572	12,334,830	31,170,402	202,874	95,226	10,987	309,088	44,377,881	788,432	45,166,313	46,456	3,267,302	50,396	48,530,467
2017	12,355,071	682,442	13,037,513	18,874,122	12,410,747	31,284,869	204,998	94,109	10,987	310,094	44,632,476	788,801	45,421,276	46,456	3,285,074	50,411	48,803,217
2018	12,531,834	685,231	13,217,065	18,964,974	12,534,877	31,499,850	207,141	92,620	10,987	310,748	45,027,663	789,173	45,816,836	46,456	3,316,893	50,426	49,230,611
2019	12,698,169	684,463	13,382,632	19,017,159	12,631,048	31,648,206	209,041	92,062	10,987	312,089	45,342,928	789,549	46,132,477	46,456	3,339,455	50,441	49,568,829
2020	12,937,911	687,570	13,625,481	19,149,638	12,781,879	31,931,517	211,004	91,680	10,987	313,671	45,870,669	789,929	46,660,598	46,456	3,380,207	50,456	50,137,716
2021	13,101,590	686,381	13,787,970	19,198,306	12,883,225	32,081,530	212,670	90,358	10,987	314,014	46,183,515	790,312	46,973,827	46,456	3,402,211	50,472	50,472,966
2022	13,269,456	688,625	13,958,080	19,281,025	13,027,833	32,308,858	214,430	89,182	10,987	314,599	46,581,538	790,700	47,372,237	46,456	3,434,154	50,487	50,903,335
2023	13,451,607	687,959	14,139,566	19,329,633	13,128,799	32,458,433	216,291	88,774	10,987	316,052	46,914,051	791,091	47,705,141	46,456	3,458,084	50,503	51,260,184
2024	13,739,117	693,417	14,432,534	19,435,114	13,280,554	32,715,668	218,072	88,074	10,987	317,133	47,465,335	791,486	48,256,821	46,456	3,499,514	50,519	51,853,309
2025	13,994,108	694,563	14,688,672	19,485,702	13,393,707	32,879,409	219,647	87,516	10,987	318,149	47,886,230	791,884	48,678,114	46,456	3,528,191	50,535	52,303,296
2026	14,248,145	698,992	14,947,137	19,599,926	13,569,114	33,169,039	221,320	86,624	10,987	318,930	48,435,107	792,287	49,227,394	46,456	3,569,685	50,551	52,894,086

Note: Retail and Wholesale losses are not broken out seprately for the years 2000-2002
3,097,174 total for 2000
3,276,358 total for 2001
3,291,377 total for 2002

	MWh Total MN ANNUAL Summary:										
	Residential w/o Sp Heat	Residential w/ Sp Heat	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept	Total Other	Total Retail
2001	7,668,253	363,330	8,031,583	13,039,381	8,355,790	21,395,171	130,612	104,998	12,942	248,552	29,675,306
2002	8,111,322	376,168	8,487,490	12,080,326	9,369,199	21,449,525	130,657	98,142	11,358	240,157	30,177,172
2003	8,097,619	384,952	8,482,571	12,300,171	9,387,479	21,687,650	129,473	104,419	13,867	247,759	30,417,981
2004	7,916,320	373,041	8,289,361	12,375,215	9,489,401	21,864,616	139,813	93,102	16,311	249,226	30,403,203
2005	8,473,184	368,762	8,841,947	13,640,412	8,993,804	22,634,216	135,989	94,761	6,133	236,883	31,713,046
2006	8,525,645	350,900	8,876,545	13,677,161	9,129,744	22,806,904	143,664	92,112	7,310	243,086	31,926,536
2007	8,747,807	375,278	9,123,085	13,722,963	9,395,486	23,118,449	135,836	89,390	12,013	237,239	32,478,773
2008	8,314,634	382,010	8,696,644	13,683,725	9,449,345	23,133,070	136,071	80,504	7,005	223,580	32,053,294
2009	8,104,166	375,107	8,479,273	13,400,674	8,551,188	21,951,862	137,899	80,183	9,072	227,154	30,658,289
2010	9,585,155	676,799	10,261,954	15,547,890	9,338,499	24,886,389	164,770	90,674	9,072	264,516	35,412,858
2011	9,726,873	676,807	10,403,681	15,643,125	9,602,248	25,245,373	167,096	87,691	9,072	263,859	35,912,912
2012	9,858,271	679,268	10,537,539	15,776,400	9,857,543	25,633,943	168,990	87,313	9,072	265,375	36,436,857
2013	9,891,130	678,366	10,569,496	15,839,817	10,055,044	25,894,861	170,927	87,687	9,072	267,686	36,732,042
2014	9,971,167	681,205	10,652,373	15,945,743	10,289,725	26,235,467	172,797	86,722	9,072	268,591	37,156,431
2015	10,046,491	679,865	10,726,356	15,976,314	10,418,762	26,395,076	174,589	85,807	9,072	269,468	37,390,899
2016	10,183,658	683,037	10,866,694	16,064,769	10,552,758	26,617,527	176,540	84,731	9,072	270,343	37,754,564
2017	10,309,389	682,442	10,991,831	16,088,262	10,607,180	26,695,442	178,427	83,709	9,072	271,208	37,958,482
2018	10,472,822	685,231	11,158,053	16,161,667	10,705,680	26,867,347	180,334	82,315	9,072	271,721	38,297,120
2019	10,629,101	684,463	11,313,564	16,201,109	10,782,599	26,983,709	181,989	81,849	9,072	272,910	38,570,183
2020	10,842,663	687,570	11,530,234	16,313,168	10,913,389	27,226,557	183,737	81,560	9,072	274,369	39,031,160
2021	10,981,958	686,381	11,668,339	16,339,519	10,994,273	27,333,792	185,192	80,329	9,072	274,593	39,276,724
2022	11,143,521	688,625	11,832,146	16,401,815	11,109,801	27,511,617	186,703	79,244	9,072	275,020	39,618,782
2023	11,305,412	687,959	11,993,371	16,431,540	11,197,617	27,629,157	188,328	78,926	9,072	276,326	39,898,854
2024	11,572,453	693,417	12,265,870	16,518,769	11,330,186	27,848,955	189,880	78,315	9,072	277,267	40,392,092
2025	11,798,789	694,563	12,493,352	16,543,971	11,423,875	27,967,846	191,331	77,844	9,072	278,247	40,739,446
2026	12,045,713	698,992	12,744,705	16,635,287	11,572,948	28,208,235	192,875	77,039	9,072	278,986	41,231,926

2011 Budget
Electric Customers

NSP - Total Company

	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept.	Total Other	Total Retail	Total Wholesale	TOTAL
2001	1,345,077	170,154	740	170,894	3,836	2,833		6,669	1,522,640	17	1,522,657
2002	1,361,938	173,240	763	174,003	4,009	2,838		6,847	1,542,788	18	1,542,806
2003	1,379,851	175,484	753	176,237	3,784	2,810		6,594	1,562,682	17	1,562,699
2004	1,404,993	179,326	769	180,095	4,299	2,813		7,112	1,592,200	20	1,592,220
2005	1,389,605	176,358	616	176,974	4,290	2,716		7,006	1,573,585	21	1,573,606
2006	1,413,729	180,050	599	180,649	4,430	2,709	37	7,176	1,601,554	24	1,601,578
2007	1,426,755	182,606	635	183,241	4,518	2,698	45	7,261	1,617,257	23	1,617,280
2008	1,437,869	184,756	619	185,375	4,533	2,688	55	7,276	1,630,520	22	1,630,542
2009	1,441,861	186,271	578	186,849	4,596	2,622	52	7,270	1,635,980	19	1,635,999
2010	1,454,358	187,441	578	188,019	4,683	2,605	51	7,339	1,649,716	16	1,649,732
2011	1,470,428	189,641	586	190,227	4,788	2,587	51	7,426	1,668,081	15	1,668,096
2012	1,486,910	191,944	594	192,538	4,893	2,571	51	7,515	1,686,963	15	1,686,978
2013	1,502,169	194,061	599	194,660	4,989	2,555	51	7,595	1,704,424	14	1,704,438
2014	1,518,397	196,208	603	196,811	5,087	2,540	51	7,678	1,722,886	14	1,722,900
2015	1,534,420	198,316	603	198,919	5,182	2,525	51	7,758	1,741,097	14	1,741,111
2016	1,550,911	200,504	602	201,106	5,278	2,511	51	7,840	1,759,857	14	1,759,871
2017	1,567,300	202,703	602	203,305	5,374	2,497	51	7,922	1,778,527	14	1,778,541
2018	1,581,514	204,630	602	205,232	5,455	2,484	51	7,990	1,794,736	14	1,794,750
2019	1,597,003	206,704	601	207,305	5,539	2,472	51	8,062	1,812,370	14	1,812,384
2020	1,611,400	208,631	604	209,235	5,613	2,460	51	8,124	1,828,759	14	1,828,773
2021	1,624,304	210,335	603	210,938	5,680	2,448	51	8,179	1,843,421	14	1,843,435
2022	1,637,885	212,121	601	212,722	5,747	2,437	51	8,235	1,858,842	14	1,858,856
2023	1,651,756	213,951	600	214,551	5,816	2,426	51	8,293	1,874,600	14	1,874,614
2024	1,664,778	215,742	598	216,340	5,882	2,415	51	8,348	1,889,466	14	1,889,480
2025	1,677,902	217,576	596	218,172	5,949	2,406	51	8,406	1,904,480	14	1,904,494
2026	1,691,145	219,401	596	219,997	6,013	2,397	51	8,461	1,919,603	14	1,919,617

2011 Budget
Electric Customers

NSP - MN

	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept.	Total Other	Total Retail	Total Wholesale	TOTAL
2001	1,017,202	144,566	117,323	261,889	2,791	2,162	0	4,953	1,284,044	7	1,284,051
2002	1,029,634	146,802	119,295	266,097	2,945	2,170	0	5,115	1,300,846	8	1,300,854
2003	1,043,231	148,558	120,818	269,376	2,712	2,142	0	4,854	1,317,461	7	1,317,468
2004	1,062,137	151,411	123,488	274,899	3,188	2,140	0	5,328	1,342,364	10	1,342,374
2005	1,047,452	147,734	120,420	268,154	3,151	2,093	0	5,244	1,320,850	11	1,320,861
2006	1,065,337	150,531	122,867	273,398	3,276	2,058	4	5,334	1,344,069	14	1,344,083
2007	1,074,894	152,441	124,648	277,089	3,346	2,049	8	5,395	1,357,378	13	1,357,391
2008	1,082,161	125,393	483	125,876	3,346	2,030	8	5,384	1,213,421	12	1,213,433
2009	1,084,245	126,373	446	126,819	3,381	2,015	8	5,404	1,216,468	9	1,216,477
2010	1,093,626	126,869	445	127,314	3,458	2,001	8	5,467	1,226,407	6	1,226,413
2011	1,105,042	128,186	453	128,639	3,541	1,985	8	5,534	1,239,215	5	1,239,220
2012	1,117,342	129,605	461	130,066	3,625	1,971	8	5,604	1,253,012	5	1,253,017
2013	1,128,703	130,915	466	131,381	3,701	1,956	8	5,665	1,265,749	4	1,265,753
2014	1,140,951	132,328	470	132,798	3,779	1,943	8	5,730	1,279,479	4	1,279,483
2015	1,152,998	133,717	470	134,187	3,854	1,930	8	5,792	1,292,977	4	1,292,981
2016	1,165,622	135,174	469	135,643	3,929	1,918	8	5,855	1,307,120	4	1,307,124
2017	1,177,972	136,598	469	137,067	4,000	1,906	8	5,914	1,320,953	4	1,320,957
2018	1,188,269	137,786	469	138,255	4,062	1,895	8	5,965	1,332,489	4	1,332,493
2019	1,200,122	139,153	468	139,621	4,128	1,884	8	6,020	1,345,763	4	1,345,767
2020	1,211,172	140,428	471	140,899	4,189	1,874	8	6,071	1,358,142	4	1,358,146
2021	1,220,685	141,525	470	141,995	4,243	1,864	8	6,115	1,368,795	4	1,368,799
2022	1,230,530	142,660	468	143,128	4,296	1,855	8	6,159	1,379,817	4	1,379,821
2023	1,240,674	143,830	467	144,297	4,350	1,846	8	6,204	1,391,175	4	1,391,179
2024	1,250,934	145,014	465	145,479	4,404	1,837	8	6,249	1,402,662	4	1,402,666
2025	1,261,789	146,266	463	146,729	4,459	1,829	8	6,296	1,414,814	4	1,414,818
2026	1,272,681	147,522	463	147,985	4,513	1,821	8	6,342	1,427,008	4	1,427,012

Annual Base Peak Demand By Customer Class

NSP 2011 Budget (IRP Forecast Prepared May 2010)

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

	Annual Base Peak Demand (Mw) by Customer Class									
		Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	System Base Peak Demand Mw
NET PEAK	2001	*NA*	*NA*	3,087	1,578	*NA*	3,581	*NA*	103	8,349
	2002	*NA*	*NA*	2,773	2,831	*NA*	2,383	*NA*	252	8,239
	2003	*NA*	*NA*	3,074	3,113	*NA*	1,933	*NA*	161	8,281
	2004	*NA*	*NA*	3,055	3,164	*NA*	2,173	*NA*	204	8,596
	2005	*NA*	*NA*	3,222	3,174	*NA*	1,884	*NA*	221	8,501
	2006	*NA*	*NA*	3,274	3,394	*NA*	2,059	*NA*	299	9,026
	2007	*NA*	*NA*	2,836	3,525	*NA*	2,182	*NA*	260	8,803
	2008	*NA*	*NA*	2,776	3,455	*NA*	2,143	*NA*	250	8,624
	2009	*NA*	*NA*	2,860	3,415	*NA*	2,051	*NA*	221	8,546
	2010	*NA*	*NA*	3,055	3,648	*NA*	2,191	*NA*	236	9,131
BASE PEAK	2011	*NA*	*NA*	3,117	3,722	*NA*	2,235	*NA*	241	9,315
	2012	*NA*	*NA*	3,173	3,789	*NA*	2,275	*NA*	245	9,483
	2013	*NA*	*NA*	3,223	3,848	*NA*	2,311	*NA*	249	9,631
	2014	*NA*	*NA*	3,272	3,907	*NA*	2,346	*NA*	253	9,779
	2015	*NA*	*NA*	3,312	3,955	*NA*	2,375	*NA*	256	9,897
	2016	*NA*	*NA*	3,352	4,002	*NA*	2,403	*NA*	259	10,016
	2017	*NA*	*NA*	3,387	4,044	*NA*	2,429	*NA*	262	10,122
	2018	*NA*	*NA*	3,422	4,087	*NA*	2,454	*NA*	265	10,228
	2019	*NA*	*NA*	3,454	4,124	*NA*	2,477	*NA*	267	10,321
	2020	*NA*	*NA*	3,488	4,165	*NA*	2,502	*NA*	270	10,425
	2021	*NA*	*NA*	3,515	4,197	*NA*	2,520	*NA*	272	10,504
	2022	*NA*	*NA*	3,542	4,230	*NA*	2,540	*NA*	274	10,586
	2023	*NA*	*NA*	3,570	4,263	*NA*	2,560	*NA*	276	10,670
	2024	*NA*	*NA*	3,599	4,298	*NA*	2,581	*NA*	278	10,757
	2025	*NA*	*NA*	3,625	4,329	*NA*	2,600	*NA*	280	10,834
	2026	*NA*	*NA*	3,657	4,367	*NA*	2,623	*NA*	283	10,930

The historical peaks by class in this table sum to the Net (interrupted) peak rather than the Base (uninterrupted peak). The forecasted peaks by class sum to the Base Peak Forecast.

In the Monthly Native Demand and Energy Table B.11.4, the historical monthly peaks are the Base Peaks. Therefore, the historical system values do not tie between Table B.11.3 and Table B.11.4.

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-01	3,639,735	6,144	31	79.60%
Feb-01	3,327,152	6,112	28	81.00%
Mar-01	3,414,582	5,624	31	81.60%
Apr-01	3,150,897	5,594	30	78.20%
May-01	3,412,524	7,200	31	63.70%
Jun-01	3,728,184	8,061	30	64.20%
Jul-01	4,347,736	9,001	31	64.90%
Aug-01	4,271,909	9,236	31	62.20%
Sep-01	3,382,565	6,924	30	67.90%
Oct-01	3,361,640	5,740	31	78.70%
Nov-01	3,266,364	6,005	30	75.50%
Dec-01	3,526,470	6,012	31	78.80%
Jan-02	3,622,279	6,187	31	78.70%
Feb-02	3,163,001	5,872	28	80.20%
Mar-02	3,548,998	5,946	31	80.20%
Apr-02	3,272,927	6,221	30	73.10%
May-02	3,348,877	7,013	31	64.20%
Jun-02	3,937,321	8,281	30	66.00%
Jul-02	4,564,178	8,924	31	68.70%
Aug-02	4,024,109	7,465	31	72.50%
Sep-02	3,707,000	8,192	30	62.80%
Oct-02	3,529,247	5,929	31	80.00%
Nov-02	3,411,544	6,070	30	78.10%
Dec-02	3,650,602	6,386	31	76.80%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-03	3,803,608	6,371	31	80.20%
Feb-03	3,384,792	6,236	28	80.80%
Mar-03	3,527,760	5,954	31	79.60%
Apr-03	3,287,588	5,755	30	79.30%
May-03	3,310,402	5,892	31	75.50%
Jun-03	3,649,429	7,760	30	65.30%
Jul-03	4,218,642	8,066	31	70.30%
Aug-03	4,354,499	8,868	31	66.00%
Sep-03	3,561,053	7,819	30	63.30%
Oct-03	3,486,682	6,128	31	76.50%
Nov-03	3,425,474	6,136	30	77.50%
Dec-03	3,723,471	6,497	31	77.00%
Jan-04	3,905,061	6,653	31	78.90%
Feb-04	3,487,426	6,320	29	79.30%
Mar-04	3,559,448	5,941	31	80.50%
Apr-04	3,259,891	5,749	30	78.80%
May-04	3,399,231	6,240	31	73.20%
Jun-04	3,661,488	8,106	30	62.70%
Jul-04	4,177,268	8,665	31	64.80%
Aug-04	3,864,519	7,920	31	65.60%
Sep-04	3,776,737	8,029	30	65.30%
Oct-04	3,546,840	5,937	31	80.30%
Nov-04	3,511,756	6,224	30	78.40%
Dec-04	3,905,782	6,873	31	76.40%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-05	3,916,456	6,636	31	79.30%
Feb-05	3,398,237	6,222	28	81.30%
Mar-05	3,667,801	5,996	31	82.20%
Apr-05	3,342,840	6,017	30	77.20%
May-05	3,525,768	6,055	31	78.30%
Jun-05	4,163,552	9,072	30	63.70%
Jul-05	4,605,640	8,945	31	69.20%
Aug-05	4,350,713	9,104	31	64.20%
Sep-05	3,853,840	7,512	30	71.30%
Oct-05	3,649,397	7,253	31	67.60%
Nov-05	3,574,084	6,466	30	76.80%
Dec-05	3,959,815	6,833	31	77.90%
Jan-06	3,852,014	6,332	31	81.80%
Feb-06	3,580,961	6,451	28	82.60%
Mar-06	3,757,537	6,058	31	83.40%
Apr-06	3,423,351	5,753	30	82.60%
May-06	3,778,659	7,273	31	69.80%
Jun-06	4,119,203	8,203	30	69.70%
Jul-06	4,895,295	9,859	31	66.70%
Aug-06	4,439,661	8,007	31	74.50%
Sep-06	3,629,557	7,132	30	70.70%
Oct-06	3,717,020	6,439	31	77.60%
Nov-06	3,647,831	6,599	30	76.80%
Dec-06	3,940,232	6,887	31	76.90%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-07	4,036,501	6,597	31	82.20%
Feb-07	3,748,020	6,740	28	82.80%
Mar-07	3,752,072	6,297	31	80.10%
Apr-07	3,528,276	5,985	30	81.90%
May-07	3,793,551	7,273	31	70.10%
Jun-07	4,261,258	9,210	30	64.30%
Jul-07	4,703,782	9,473	31	66.70%
Aug-07	4,546,156	9,051	31	67.50%
Sep-07	3,917,770	8,919	30	61.00%
Oct-07	3,823,393	6,710	31	76.60%
Nov-07	3,715,683	6,798	30	75.90%
Dec-07	4,124,795	6,968	31	79.60%
Jan-08	4,208,150	6,953	31	81.30%
Feb-08	3,900,939	6,900	29	81.20%
Mar-08	3,831,023	6,369	31	80.80%
Apr-08	3,580,870	5,917	30	84.10%
May-08	3,568,644	5,917	31	81.10%
Jun-08	3,860,078	8,001	30	67.00%
Jul-08	4,528,627	8,694	31	70.00%
Aug-08	4,416,662	8,432	31	70.40%
Sep-08	3,773,757	7,486	30	70.00%
Oct-08	3,694,984	6,048	31	82.10%
Nov-08	3,651,191	6,494	30	78.10%
Dec-08	4,130,010	7,226	31	76.80%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-09	4,126,200	6,948	31	79.8%
Feb-09	3,574,053	6,597	28	80.6%
Mar-09	3,716,482	6,247	31	80.0%
Apr-09	3,410,854	5,757	30	82.3%
May-09	3,483,284	6,994	31	66.9%
Jun-09	3,847,934	8,609	30	62.1%
Jul-09	3,989,892	7,448	31	72.0%
Aug-09	4,089,921	8,248	31	66.6%
Sep-09	3,805,139	7,112	30	74.3%
Oct-09	3,630,942	5,882	31	83.0%
Nov-09	3,516,847	6,165	30	79.2%
Dec-09	4,032,800	6,971	31	77.8%
Jan-10	4,016,560	6,634	31	81.4%
Feb-10	3,595,141	6,500	28	82.3%
Mar-10	3,758,057	6,166	31	81.9%
Apr-10	3,365,964	5,939	30	78.7%
May-10	3,570,730	6,877	31	69.8%
Jun-10	3,856,799	8,613	30	62.2%
Jul-10	4,411,282	9,140	31	64.9%
Aug-10	4,281,570	8,823	31	65.2%
Sep-10	3,694,633	7,999	30	64.2%
Oct-10	3,573,297	6,147	31	78.1%
Nov-10	3,599,894	6,649	30	75.2%
Dec-10	3,925,780	7,097	31	74.3%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-11	4,016,096	6,960	31	77.6%
Feb-11	3,640,057	6,793	28	79.7%
Mar-11	3,795,245	6,416	31	79.5%
Apr-11	3,420,924	6,145	30	77.3%
May-11	3,618,592	7,072	31	68.8%
Jun-11	3,914,676	8,801	30	61.8%
Jul-11	4,477,043	9,315	31	64.6%
Aug-11	4,328,479	8,980	31	64.8%
Sep-11	3,717,147	8,168	30	63.2%
Oct-11	3,627,084	6,251	31	78.0%
Nov-11	3,655,389	6,785	30	74.8%
Dec-11	3,980,554	7,238	31	73.9%
Jan-12	4,077,052	7,096	31	77.2%
Feb-12	3,726,633	6,928	29	77.3%
Mar-12	3,853,991	6,552	31	79.1%
Apr-12	3,477,364	6,277	30	76.9%
May-12	3,664,833	7,234	31	68.1%
Jun-12	3,982,324	8,969	30	61.7%
Jul-12	4,528,399	9,483	31	64.2%
Aug-12	4,377,868	9,146	31	64.3%
Sep-12	3,763,901	8,343	30	62.7%
Oct-12	3,651,670	6,358	31	77.2%
Nov-12	3,689,995	6,922	30	74.0%
Dec-12	4,029,785	7,380	31	73.4%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-13	4,116,505	7,238	31	76.4%
Feb-13	3,725,052	7,068	28	78.4%
Mar-13	3,875,846	6,682	31	78.0%
Apr-13	3,517,683	6,394	30	76.4%
May-13	3,730,656	7,388	31	67.9%
Jun-13	4,005,391	9,123	30	61.0%
Jul-13	4,579,694	9,631	31	63.9%
Aug-13	4,425,284	9,287	31	64.0%
Sep-13	3,781,725	8,489	30	61.9%
Oct-13	3,690,111	6,436	31	77.1%
Nov-13	3,725,711	7,029	30	73.6%
Dec-13	4,040,032	7,490	31	72.5%
Jan-14	4,141,894	7,350	31	75.7%
Feb-14	3,758,862	7,181	28	77.9%
Mar-14	3,903,436	6,795	31	77.2%
Apr-14	3,537,979	6,503	30	75.6%
May-14	3,783,006	7,530	31	67.5%
Jun-14	4,056,240	9,271	30	60.8%
Jul-14	4,611,677	9,779	31	63.4%
Aug-14	4,450,386	9,434	31	63.4%
Sep-14	3,863,621	8,644	30	62.1%
Oct-14	3,745,504	6,521	31	77.2%
Nov-14	3,782,765	7,142	30	73.6%
Dec-14	4,121,626	7,610	31	72.8%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-15	4,162,780	7,465	31	74.9%
Feb-15	3,786,867	7,290	28	77.3%
Mar-15	3,930,033	6,898	31	76.6%
Apr-15	3,568,938	6,598	30	75.1%
May-15	3,806,304	7,650	31	66.9%
Jun-15	4,073,377	9,392	30	60.2%
Jul-15	4,656,678	9,897	31	63.2%
Aug-15	4,463,649	9,549	31	62.8%
Sep-15	3,867,036	8,765	30	61.3%
Oct-15	3,785,691	6,576	31	77.4%
Nov-15	3,820,325	7,227	30	73.4%
Dec-15	4,154,991	7,692	31	72.6%
Jan-16	4,186,210	7,549	31	74.5%
Feb-16	3,854,582	7,374	29	75.1%
Mar-16	3,960,190	6,979	31	76.3%
Apr-16	3,660,319	6,674	30	76.2%
May-16	3,781,847	7,764	31	65.5%
Jun-16	4,134,150	9,512	30	60.4%
Jul-16	4,662,584	10,016	31	62.6%
Aug-16	4,468,914	9,666	31	62.1%
Sep-16	3,968,942	8,891	30	62.0%
Oct-16	3,741,685	6,628	31	75.9%
Nov-16	3,854,730	7,307	30	73.3%
Dec-16	4,256,316	7,778	31	73.5%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-17	4,200,911	7,636	31	73.9%
Feb-17	3,829,009	7,457	28	76.4%
Mar-17	4,028,220	7,060	31	76.7%
Apr-17	3,641,279	6,745	30	75.0%
May-17	3,840,622	7,869	31	65.6%
Jun-17	4,165,429	9,620	30	60.1%
Jul-17	4,670,799	10,122	31	62.0%
Aug-17	4,549,838	9,773	31	62.6%
Sep-17	3,948,294	9,004	30	60.9%
Oct-17	3,784,197	6,676	31	76.2%
Nov-17	3,933,092	7,388	30	73.9%
Dec-17	4,211,526	7,860	31	72.0%
Jan-18	4,272,998	7,720	31	74.4%
Feb-18	3,866,189	7,542	28	76.3%
Mar-18	3,985,139	7,139	31	75.0%
Apr-18	3,670,971	6,818	30	74.8%
May-18	3,934,972	7,978	31	66.3%
Jun-18	4,153,873	9,729	30	59.3%
Jul-18	4,725,377	10,228	31	62.1%
Aug-18	4,559,755	9,874	31	62.1%
Sep-18	3,983,778	9,112	30	60.7%
Oct-18	3,858,770	6,721	31	77.2%
Nov-18	3,932,282	7,464	30	73.2%
Dec-18	4,286,508	7,942	31	72.5%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-19	4,265,731	7,801	31	73.5%
Feb-19	3,896,837	7,621	28	76.1%
Mar-19	4,040,958	7,219	31	75.2%
Apr-19	3,709,392	6,892	30	74.8%
May-19	3,920,279	8,068	31	65.3%
Jun-19	4,176,841	9,824	30	59.1%
Jul-19	4,810,602	10,321	31	62.6%
Aug-19	4,552,600	9,970	31	61.4%
Sep-19	3,989,785	9,216	30	60.1%
Oct-19	3,905,250	6,764	31	77.6%
Nov-19	3,973,067	7,542	30	73.2%
Dec-19	4,327,486	8,024	31	72.5%
Jan-20	4,314,067	7,885	31	73.5%
Feb-20	3,985,224	7,707	29	74.3%
Mar-20	4,091,512	7,301	31	75.3%
Apr-20	3,786,115	6,968	30	75.5%
May-20	3,904,105	8,176	31	64.2%
Jun-20	4,267,662	9,935	30	59.7%
Jul-20	4,810,777	10,425	31	62.0%
Aug-20	4,607,828	10,073	31	61.5%
Sep-20	4,111,676	9,329	30	61.2%
Oct-20	3,858,855	6,811	31	76.1%
Nov-20	3,993,045	7,624	30	72.7%
Dec-20	4,406,851	8,110	31	73.0%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-21	4,337,502	7,971	31	73.1%
Feb-21	3,968,151	7,789	28	75.8%
Mar-21	4,176,190	7,381	31	76.0%
Apr-21	3,766,306	7,039	30	74.3%
May-21	3,974,377	8,262	31	64.7%
Jun-21	4,302,017	10,019	30	59.6%
Jul-21	4,821,548	10,504	31	61.7%
Aug-21	4,695,302	10,153	31	62.2%
Sep-21	4,085,755	9,413	30	60.3%
Oct-21	3,909,354	6,847	31	76.7%
Nov-21	4,081,426	7,702	30	73.6%
Dec-21	4,355,037	8,188	31	71.5%
Jan-22	4,411,425	8,051	31	73.6%
Feb-22	4,006,421	7,869	28	75.8%
Mar-22	4,123,482	7,456	31	74.3%
Apr-22	3,797,607	7,109	30	74.2%
May-22	4,075,756	8,348	31	65.6%
Jun-22	4,285,862	10,105	30	58.9%
Jul-22	4,877,070	10,586	31	61.9%
Aug-22	4,704,127	10,235	31	61.8%
Sep-22	4,119,280	9,503	30	60.2%
Oct-22	3,991,334	6,884	31	77.9%
Nov-22	4,077,001	7,775	30	72.8%
Dec-22	4,433,970	8,269	31	72.1%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-23	4,403,773	8,130	31	72.8%
Feb-23	4,040,456	7,947	28	75.7%
Mar-23	4,184,242	7,534	31	74.6%
Apr-23	3,839,829	7,182	30	74.3%
May-23	4,058,896	8,437	31	64.7%
Jun-23	4,311,467	10,195	30	58.7%
Jul-23	4,967,596	10,670	31	62.6%
Aug-23	4,695,404	10,320	31	61.2%
Sep-23	4,126,770	9,595	30	59.7%
Oct-23	4,039,644	6,920	31	78.5%
Nov-23	4,117,766	7,851	30	72.8%
Dec-23	4,474,340	8,348	31	72.0%
Jan-24	4,455,646	8,213	31	72.9%
Feb-24	4,128,666	8,031	29	73.9%
Mar-24	4,239,164	7,615	31	74.8%
Apr-24	3,920,719	7,258	30	75.0%
May-24	4,039,130	8,532	31	63.6%
Jun-24	4,407,632	10,290	30	59.5%
Jul-24	4,964,949	10,757	31	62.0%
Aug-24	4,751,929	10,409	31	61.4%
Sep-24	4,257,330	9,692	30	61.0%
Oct-24	3,987,006	6,961	31	77.0%
Nov-24	4,139,281	7,931	30	72.5%
Dec-24	4,561,857	8,432	31	72.7%

Monthly Native Energy and Demand Requirements

NSP 2010 Budget

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jan-25	4,480,908	8,300	31	72.6%
Feb-25	4,120,234	8,114	28	75.6%
Mar-25	4,342,998	7,697	31	75.8%
Apr-25	3,901,229	7,332	30	73.9%
May-25	4,119,669	8,617	31	64.3%
Jun-25	4,456,837	10,374	30	59.7%
Jul-25	4,982,239	10,834	31	61.8%
Aug-25	4,856,565	10,491	31	62.2%
Sep-25	4,236,943	9,777	30	60.2%
Oct-25	4,046,834	6,999	31	77.7%
Nov-25	4,246,873	8,013	30	73.6%
Dec-25	4,511,967	8,515	31	71.2%
Jan-26	4,577,662	8,392	31	73.3%
Feb-26	4,171,233	8,207	28	75.6%
Mar-26	4,285,716	7,783	31	74.0%
Apr-26	3,948,479	7,413	30	74.0%
May-26	4,247,535	8,717	31	65.5%
Jun-26	4,444,306	10,474	30	58.9%
Jul-26	5,058,104	10,930	31	62.2%
Aug-26	4,878,298	10,586	31	61.9%
Sep-26	4,278,930	9,878	30	60.2%
Oct-26	4,151,373	7,046	31	79.2%
Nov-26	4,246,628	8,097	30	72.8%
Dec-26	4,605,823	8,606	31	71.9%

Seasonal Firm Purchases - Summer

		Minnesota Power	Omaha Public Power District	Central MN Municipal Power Coop	Basin Electric Power Compnay	Great River Energy	Western Area Power Administration	Manitoba 150	Manitoba 200	Total
2001	SUMMER	85		15	50	75	2	150	200	577
2002	SUMMER				50	75	2	150	200	477
2003	SUMMER		35		50	75	2	150	200	512
2004	SUMMER				50	75	2	150	200	477
2005	SUMMER				50	75	2	150	200	477
2006	SUMMER				54	81	2	150	200	487
2007	SUMMER						2	150	200	352
2008	SUMMER						2	150	200	352
2009	SUMMER						2	150	200	352
2010	SUMMER						2	150	200	352
2011	SUMMER						2	150	200	352
2012	SUMMER						2	150	200	352
2013	SUMMER						2	150	200	352
2014	SUMMER						2	150	200	352
2015	SUMMER						2	150	200	352
2016	SUMMER						2	150	200	352
2017	SUMMER						2	150	200	352
2018	SUMMER						2	150	200	352
2019	SUMMER						2	150	200	352
2020	SUMMER						2	150	200	352
2021	SUMMER							150	200	350
2022	SUMMER							150	200	350
2023	SUMMER							150	200	350
2024	SUMMER							150	200	350
2025	SUMMER									0
2026	SUMMER									0

Seasonal Firm Purchases - Winter

		Central MN Municipal Power Agency	Basin Elec. Power Corp	Great River Energy	Western Area Power Administration	Total
2001	WINTER	11	50	75		136
2002	WINTER	12	50	75	2	139
2003	WINTER				2	2
2004	WINTER		50	75	2	127
2005	WINTER		50	75	2	127
2006	WINTER		54	75	2	131
2007	WINTER				2	2
2008	WINTER				2	2
2009	WINTER				2	2
2010	WINTER				2	2
2011	WINTER				2	2
2012	WINTER				2	2
2013	WINTER				2	2
2014	WINTER				2	2
2015	WINTER				2	2
2016	WINTER				2	2
2017	WINTER				2	2
2018	WINTER				2	2
2019	WINTER				2	2
2020	WINTER				2	2
2021	WINTER					0
2022	WINTER					0
2023	WINTER					0
2024	WINTER					0
2025	WINTER					0
2026	WINTER					0

Sesonal Firm Sales - SUMMER

		Municipals	Total
2001	SUMMER	15	15
2002	SUMMER	15	15
2003	SUMMER	15	15
2004	SUMMER	16	16
2005	SUMMER		0
2006	SUMMER		0
2007	SUMMER		0
2008	SUMMER		0
2009	SUMMER		0
2010	SUMMER		0
2011	SUMMER		0
2012	SUMMER		0
2013	SUMMER		0
2014	SUMMER		0
2015	SUMMER		0
2016	SUMMER		0
2017	SUMMER		0
2018	SUMMER		0
2019	SUMMER		0
2020	SUMMER		0
2021	SUMMER		0
2022	SUMMER		0
2023	SUMMER		0
2024	SUMMER		0
2025	SUMMER		0
2026	SUMMER		0

Seasonal Firm Sales - WINTER

		Municipals	Wisconsin Rapids	Barron	Manitoba 150	Manitoba 200	Total
2001	WINTER	11	15	8	150	200	384
2002	WINTER	12			150	200	362
2003	WINTER	15			150	200	365
2004	WINTER	15			150	200	365
2005	WINTER	16			150	200	366
2006	WINTER	15			150	200	365
2007	WINTER				150	200	350
2008	WINTER				150	200	350
2009	WINTER				150	200	350
2010	WINTER				150	200	350
2011	WINTER				150	200	350
2012	WINTER				150	200	350
2013	WINTER				150	200	350
2014	WINTER				150	200	350
2015	WINTER				150	200	350
2016	WINTER				150	200	350
2017	WINTER				150	200	350
2018	WINTER				150	200	350
2019	WINTER				150	200	350
2020	WINTER				150	200	350
2021	WINTER				150	200	350
2022	WINTER				150	200	350
2023	WINTER				150	200	350
2024	WINTER				150	200	350
2025	WINTER						0
2026	WINTER						0

Seasonal Participation Purchase -- SUMMER

		Ameren Energy Marketing Corp	Black Hills Power and Light	Calpine	Calpine Mankato	Central Iowa Power Coop	Central MN Municipal Power Agency	Constellation Commodities Group	Coyote	Cyprus	Detroit Edison	Dynegy Power Marketing	Dynegy Power Marketing	Enron Power Marketing	Exelon	Fibro Minn	Gen Sys Energy	Generic PPA	Generic Wind	Great River Energy	Hutchinson Utilities Commission	Invenergy	Kansas City Power and Light	Laurentian
2001	SUMMER	148				25			150				100	100										
2002	SUMMER	235	40						100				150				20				6		25	
2003	SUMMER	255					25		100				100											
2004	SUMMER	235					25		100				100				50							
2005	SUMMER	0					25	100	100				158				70							
2006	SUMMER	0		20	320			62	100	40	69	108	300		125							0		0
2007	SUMMER	100			312			285	100	40		108	550			50				160	20	0		35
2008	SUMMER				312			90	100	40		108	150			50						301		35
2009	SUMMER				312			95	100	40						50						301		35
2010	SUMMER				312			100	100	40						50						301		35
2011	SUMMER				312				100	40						50						301		35
2012	SUMMER				312				100							50			16			301		35
2013	SUMMER				312				100							50			24			301		35
2014	SUMMER				312				100							50			32			301		35
2015	SUMMER				312				100							50			565			301		35
2016	SUMMER				312											50		195	573			301		35
2017	SUMMER				312											50		390	781			301		35
2018	SUMMER				312											50		585	789			301		35
2019	SUMMER				312											50		585	797			301		35
2020	SUMMER				312											50		975	813			301		35
2021	SUMMER				312											50		975	938			301		35
2022	SUMMER				312											50		975	954			301		35
2023	SUMMER				312											50		975	954			301		35
2024	SUMMER				312											50		1365	970			301		35
2025	SUMMER				312											50		2468	136					35
2026	SUMMER															50		3044	160					35

Seasonal Participation Purchase -- SUMMER

		LS Power	Madelia	Manitoba Hydro	Manitoba Hydro Baseload	MidAmerican Energy Corp	Minnesota Power	Minnkota Power Coop	MN Municipal Power Agency	MPEX (a division of MP)	Non-Utility Group	Northern Indiana Public Service Co	Omaha Public Power District	Otter Tail Power	Reliant Energy Services	Short Term	Split Rock Energy	St. Paul	The Energy Authority	United Power Assoc	Utilicorp United	Utilicorp United	Western Resources Inc.	Wind	Wisconsin Public Service	Total
2001	SUMMER		8	700				20		15	365	50		75	50					50	100		83			2039
2002	SUMMER			600		150	50	20			364			75			50		30	50	50	10				2025
2003	SUMMER			760		150	100	0			381		10	75					20	50			61			2087
2004	SUMMER			960		150	100	0			381			75			100			50						2326
2005	SUMMER			700			100	0	130		381			50						50					200	2064
2006	SUMMER	245		713			100	100			85					0	200	25		50				61	50	2773
2007	SUMMER	245		500			100	100	10		85					0		25		50				76		2951
2008	SUMMER	245		713				100	10		85					642		25		50				76		3132
2009	SUMMER	245		713				100	10		85					165		25		50				96		2422
2010	SUMMER	245		500				100	10		85					265		25		50				102		2320
2011	SUMMER	245		500				100			85							25						119		1911
2012	SUMMER	245		500				100			85							25						127		1896
2013	SUMMER	245		500				100			85							25						127		1904
2014	SUMMER	245		500				100			82					36		25						127		1945
2015	SUMMER	245			375			100			82					292		25						127		2609
2016	SUMMER	245			375						82							25						127		2320
2017	SUMMER	245			375						79					114		25						127		2834
2018	SUMMER	245			375						45					290		25						127		3180
2019	SUMMER	245			375						45					191		25						116		3077
2020	SUMMER	245			375						40					275		25						115		3562
2021	SUMMER	245			500						40					220		25						115		3756
2022	SUMMER	245			500						30					283		25						115		3825
2023	SUMMER	245			500						30					193		25						103		3723
2024	SUMMER	245			500						30					284								87		4179
2025	SUMMER	245									30					149								85		3510
2026	SUMMER	245									30					0								82		3646

Seasonal Participation Purchase -- WINTER

		American Energy Marketing Corp	Barron	Calpine Mankato	Central MN Municipal Power Agency	Coyote	Cyprus	Dynegy Power Marketing	Fibro Minn	Generic PPA	Generic Wind	Gen Sys Energy	Invenergy	Laurentian	LS Power	Madelia	Manitoba Hydro	Manitoba Hydro Baseload	MidAmerican Energy Corp	Minnesota Power	Minnkota Power Coop	Non-Utility Group	St. Paul	Western Resources Inc.	Wind	Wisconsin Public Service	Total
2001	WINTER	100	4		2	150		100								8	500					377					1,241
2002	WINTER		4			100		100									500			50		373		61			1,188
2003	WINTER		4		25	100		100									500		50		20	377					1,176
2004	WINTER				25	100											500			100		398					1,123
2005	WINTER				25	100						50					500			100		398					1,173
2006	WINTER			375	31	100	40					50	0	0	275		500			100		85	25		61	87	1,729
2007	WINTER			375		100	40	108	50				0	35	275		713			100		85	25		76		1,982
2008	WINTER			375		100	40		50				350	35	275		713					85	25		76		2,124
2009	WINTER			375		100	40		50				350	35	275		500					85	25		96		1,931
2010	WINTER			375		100	40		50				350	35	275		500					85	25		102		1,937
2011	WINTER			375		100	40		50				350	35	275		500					85	25		119		1,953
2012	WINTER			375		100			50		16		350	35	275		500					85	25		127		1,938
2013	WINTER			375		100			50		24		350	35	275		500					85	25		127		1,946
2014	WINTER			375		100			50		32		350	35	275		500					82	25		127		1,951
2015	WINTER			375					50		565		350	35	275			375				82	25		127		2,259
2016	WINTER			375					50	224	573		350	35	275			375				82	25		127		2,491
2017	WINTER			375					50	449	781		350	35	275			375				79	25		127		2,921
2018	WINTER			375					50	673	789		350	35	275			375				45	25		127		3,119
2019	WINTER			375					50	673	797		350	35	275			375				45	25		116		3,116
2020	WINTER			375					50	1121	813		350	35	275			375				40	25		115		3,575
2021	WINTER			375					50	1121	938		350	35	275			375				40	25		115		3,699
2022	WINTER			375					50	1121	954		350	35	275			500				30	25		115		3,830
2023	WINTER			375					50	1121	954		350	35	275			500				30	25		103		3,818
2024	WINTER			375					50	1570	970		350	35	275			500				30			87		4,242
2025	WINTER			375					50	2838	136			35	275							30			85		3,825
2026	WINTER								50	3501	160			35	275							30			82		4,133

Seasonal Participation Sales - SUMMER

		Constellation Comm. Group	Gensys Energy	Great River Energy	Melrose	Montana Dakota Util	Montana Dakota Util	Otter Tail Power	Wisconsin Public Service	**Total**
2001	SUMMER				3				200	203
2002	SUMMER								200	200
2003	SUMMER									0
2004	SUMMER									0
2005	SUMMER								200	200
2006	SUMMER			50				32		82
2007	SUMMER	100	50	100		85	10			345
2008	SUMMER			150		90	10			250
2009	SUMMER					95	10			105
2010	SUMMER					100	10			110
2011	SUMMER									0
2012	SUMMER									0
2013	SUMMER									0
2014	SUMMER									0
2015	SUMMER									0
2016	SUMMER									0
2017	SUMMER									0
2018	SUMMER									0
2019	SUMMER									0
2020	SUMMER									0
2021	SUMMER									0
2022	SUMMER									0
2023	SUMMER									0
2024	SUMMER									0
2025	SUMMER									0
2026	SUMMER									0

Seasonal Participation Sales - WINTER

		Melrose	Minnkota Power	Municipals	Otter Tail Power	United Power Assoc	Total
2001	WINTER	3	50		75	50	178
2002	WINTER			10	75	50	135
2003	WINTER				75	50	125
2004	WINTER	3			75	50	128
2005	WINTER	3				50	53
2006	WINTER					50	50
2007	WINTER					50	50
2008	WINTER					50	50
2009	WINTER					50	50
2010	WINTER					50	50
2011	WINTER						0
2012	WINTER						0
2013	WINTER						0
2014	WINTER						0
2015	WINTER						0
2016	WINTER						0
2017	WINTER						0
2018	WINTER						0
2019	WINTER						0
2020	WINTER						0
2021	WINTER						0
2022	WINTER						0
2023	WINTER						0
2024	WINTER						0
2025	WINTER						0
2026	WINTER						0

Load and Generating Capacity Data Excluding Plants Needing a CON - SUMMER

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capactiy Obligation	Surplus or Deficit Capacity
2001	8349	8349	577	15	7787	7787	7153	2039	203	8988	1168	8955	34
2002	8239	8239	477	15	7777	7777	7275	2025	200	9100	1167	8943	157
2003	8281	8281	512	15	7784	7784	7226	2087	0	9313	1168	8951	362
2004	8596	8596	477	16	8135	8135	7229	2326	0	9555	1220	9355	200
2005	8501	8501	477	0	8024	8024	7732	2064	200	9596	1204	9227	369
2006	9034	9034	487	0	8547	8547	7627	2773	82	10318	1282	9829	489
2007	9427	9427	352	0	9075	9075	7577	2951	345	10183	1361	10436	-254
2008	10302	10302	352	0	9950	9950	7432	3132	250	10314	1493	11443	-1129
2009	8749	8749	352	0	8397	8397	7561	2422	105	9878	1260	9656	222
2010	8826	8826	352	0	8474	8474	7582	2320	110	9791	1017	9491	301
2011	9315	9315	352	0	7938	7938	7497	1911	0	9408	953	8891	517
2012	9483	9483	352	0	8090	8090	7686	1880	0	9566	971	9060	506
2013	9621	9621	352	0	8219	8219	7819	1880	0	9699	986	9205	494
2014	9761	9761	352	0	8351	8351	7894	1913	0	9807	1002	9353	454
2015	9873	9873	2	0	8804	8804	7095	1669	0	8764	1057	9861	-1097
2016	9985	9985	2	0	8916	8916	7093	1177	0	8270	1070	9986	-1716
2017	10082	10082	2	0	9014	9014	6574	1288	0	7862	1082	10095	-2233
2018	10180	10180	2	0	9111	9111	6162	1431	0	7593	1093	10204	-2612
2019	10263	10263	2	0	9194	9194	6456	1320	0	7777	1103	10297	-2521
2020	10353	10353	2	0	9284	9284	5989	1399	0	7388	1114	10398	-3011
2021	10415	10415	0	0	9349	9349	5919	1343	0	7262	1122	10471	-3208
2022	10477	10477	0	0	9410	9410	5856	1396	0	7252	1129	10539	-3287
2023	10538	10538	0	0	9471	9471	6116	1294	0	7410	1137	10608	-3197
2024	10593	10593	0	0	9527	9527	5633	1344	0	6977	1143	10670	-3693
2025	10633	10633	0	0	9567	9567	6482	906	0	7388	1148	10715	-3327
2026	10685	10685	0	0	9618	9618	6552	442	0	6994	1154	10772	-3778

NOTES :

1. Forecasted demand values based on a 50% forecast level with a DSM Adjustment and Load Management
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April
3. Wind resources are included in net generating capacity. New wind resources are projected to be accredited at 8% nameplate capa
Actual winter accreditation is likely to be higher.

Load and Generating Capacity Data Excluding Plants Needing a CON - WINTER

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capactiy Obligation	Surplus or Deficit Capacity
2001	6557	8349	136	384	6805	8597	7534	1241	178	8596	1290	8095	502
2002	6221	8239	139	362	6444	8462	7491	1188	135	8544	1269	7713	831
2003	6386	8281	2	365	6749	8644	7738	1176	125	8789	1297	8045	743
2004	6653	8596	127	365	6891	8834	7718	1123	128	8713	1325	8216	497
2005	6873	8501	127	366	7112	8740	7718	1173	53	8838	1311	8423	415
2006	6833	9034	131	365	7067	9268	7936	1729	50	9615	1390	8457	1158
2007	7413	9427	2	350	7760	9775	7616	1982	50	9548	1466	9227	321
2008	7509	10302	2	350	7856	10650	7895	2124	50	9969	1598	9454	515
2009	6915	8749	2	350	7263	9096	7773	1931	50	9654	1364	8627	1027
2010	6893	8826	2	350	7241	9174	8368	1937	50	10254	1101	8342	1912
2011	7193	9315	2	350	6515	7938	7120	1953	0	9073	953	7468	1605
2012	7312	9483	2	350	6618	8090	7211	1922	0	9133	971	7589	1543
2013	7430	9621	2	350	6728	8219	7071	1922	0	8993	986	7714	1278
2014	7559	9761	2	0	6498	8351	7131	1919	0	9050	1002	7500	1550
2015	7650	9873	2	0	6582	8804	6693	1319	0	8012	1057	7638	373
2016	7745	9985	2	0	6676	8916	6332	1319	0	7651	1070	7746	-95
2017	7836	10082	2	0	6767	9014	5700	1316	0	7016	1082	7848	-832
2018	7928	10180	2	0	6859	9111	5427	1282	0	6709	1093	7953	-1243
2019	8017	10263	2	0	6948	9194	5649	1271	0	6920	1103	8051	-1131
2020	8109	10353	2	0	7041	9284	5167	1266	0	6433	1114	8155	-1722
2021	8193	10415	0	0	7127	9349	5163	1265	0	6428	1122	8249	-1821
2022	8279	10477	0	0	7212	9410	5028	1255	0	6283	1129	8341	-2058
2023	8364	10538	0	0	7298	9471	5237	1243	0	6480	1137	8434	-1954
2024	8473	10593	0	0	7406	9527	4773	1202	0	5975	1143	8550	-2574
2025	8581	10633	0	0	7514	9567	6220	850	0	7071	1148	8662	-1591
2026	8581	10685	0	0	7514	9618	6113	472	0	6585	1154	8668	-2083

NOTES :

1. Forecasted demand values based on a 50% forecast level with a DSM Adjustment and Load Management
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April
3. Wind resources are included in net generating capacity. New wind resources are projected to be accredited at 8% nameplate capacity. Actual winter accreditation is likely to be higher.

Load and Generating Capacity Data Including Plants Needing a CON - SUMMER

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capacity Obligation	Surplus or Deficit Capacity
2001	8349	8349	577	15	7787	7787	7153	2039	203	8988	1168	8955	34
2002	8239	8239	477	15	7777	7777	7275	2025	200	9100	1167	8943	157
2003	8281	8281	512	15	7784	7784	7226	2087	0	9313	1168	8951	362
2004	8596	8596	477	16	8135	8135	7229	2326	0	9555	1220	9355	200
2005	8501	8501	477	0	8024	8024	7732	2064	200	9596	1204	9227	369
2006	9034	9034	487	0	8547	8547	7627	2773	82	10318	1282	9829	489
2007	9427	9427	352	0	9075	9075	7577	2951	345	10183	1361	10436	-254
2008	10302	10302	352	0	9950	9950	7432	3132	250	10314	1493	11443	-1129
2009	8749	8749	352	0	8397	8397	7561	2422	105	9878	1260	9656	222
2010	8826	8826	352	0	8474	8474	7582	2320	110	9791	1017	9491	301
2011	9315	9315	352	0	7938	7938	7497	1911	0	9408	953	8891	517
2012	9483	9483	352	0	8090	8090	7686	1880	0	9566	971	9060	506
2013	9621	9621	352	0	8219	8219	7819	1880	0	9699	986	9205	494
2014	9761	9761	352	0	8351	8351	7894	1913	0	9807	1002	9353	454
2015	9873	9873	352	0	8454	8454	7095	1669	0	8764	1015	9469	-705
2016	9985	9985	352	0	8566	8566	7797	1177	0	8974	1028	9594	-620
2017	10082	10082	352	0	8664	8664	7277	1288	0	8566	1040	9703	-1137
2018	10180	10180	352	0	8761	8761	6866	1431	0	8296	1051	9812	-1516
2019	10263	10263	352	0	8844	8844	7160	1320	0	8480	1061	9905	-1425
2020	10353	10353	352	0	8934	8934	6693	1399	0	8091	1072	10006	-1915
2021	10415	10415	350	0	8999	8999	6623	1343	0	7966	1080	10079	-2113
2022	10477	10477	350	0	9060	9060	6560	1396	0	7956	1087	10147	-2191
2023	10538	10538	350	0	9121	9121	6820	1294	0	8114	1095	10216	-2102
2024	10593	10593	350	0	9177	9177	6336	1344	0	7681	1101	10278	-2597
2025	10633	10633	0	0	9567	9567	7186	906	0	8092	1148	10715	-2623
2026	10685	10685	0	0	9618	9618	7256	442	0	7698	1154	10772	-3074

NOTES :

1. Forecasted demand values based on a 50% forecast level with a DSM Adjustment and Load Management
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April
3. Wind resources are included in net generating capacity. New wind resources are projected to be accredited at 8% nameplate capacity.

Load and Generating Capacity Data Including Plants Needing a CON - WINTER

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capactiy Obligation	Surplus or Deficit Capacity
2001	6557	8349	136	384	6805	8597	7534	1241	178	8596	1290	8095	502
2002	6221	8239	139	362	6444	8462	7491	1188	135	8544	1269	7713	831
2003	6386	8281	2	365	6749	8644	7738	1176	125	8789	1297	8045	743
2004	6653	8596	127	365	6891	8834	7718	1123	128	8713	1325	8216	497
2005	6873	8501	127	366	7112	8740	7718	1173	53	8838	1311	8423	415
2006	6833	9034	131	365	7067	9268	7936	1729	50	9615	1390	8457	1158
2007	7413	9427	2	350	7760	9775	7616	1982	50	9548	1466	9227	321
2008	7509	10302	2	350	7856	10650	7895	2124	50	9969	1598	9454	515
2009	6915	8749	2	350	7263	9096	7773	1931	50	9654	1364	8627	1027
2010	6893	8826	2	350	7241	9174	8368	1937	50	10254	1101	8342	1912
2011	7193	9315	2	350	6515	7938	7120	1953	0	9073	953	7468	1605
2012	7312	9483	2	350	6618	8090	7211	1922	0	9133	971	7589	1543
2013	7430	9621	2	350	6728	8219	7071	1922	0	8993	986	7714	1278
2014	7559	9761	2	350	6848	8351	7131	1919	0	9050	1002	7850	1200
2015	7650	9873	2	350	6932	8454	6693	1319	0	8012	1015	7946	65
2016	7745	9985	2	350	7026	8566	7136	1319	0	8455	1028	8054	401
2017	7836	10082	2	350	7117	8664	6504	1316	0	7820	1040	8156	-336
2018	7928	10180	2	350	7209	8761	6231	1282	0	7513	1051	8261	-747
2019	8017	10263	2	350	7298	8844	6453	1271	0	7724	1061	8359	-635
2020	8109	10353	2	350	7391	8934	5971	1266	0	7237	1072	8463	-1226
2021	8193	10415	0	350	7477	8999	5967	1265	0	7232	1080	8557	-1325
2022	8279	10477	0	350	7562	9060	5832	1255	0	7087	1087	8649	-1562
2023	8364	10538	0	350	7648	9121	6041	1243	0	7284	1095	8742	-1458
2024	8473	10593	0	350	7756	9177	5577	1202	0	6779	1101	8858	-2078
2025	8581	10633	0	0	7514	9567	7024	850	0	7875	1148	8662	-787
2026	8581	10685	0	0	7514	9618	6917	472	0	7389	1154	8668	-1279

NOTES :

1. Forecasted demand values based on a 50% forecast level with a DSM Adjustment and Load Management
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April
3. Wind resources are included in net generating capacity. New wind resources are projected to be accredited at 13.5% nameplate capacity. Actual winter accreditation is likely to be higher.

Load and Generating Capacity Data Including Future Plants Needing a CON - SUMMER

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capacity Obligation	Surplus or Deficit Capacity
2001	8349	8349	577	15	7787	7787	7153	2039	203	8988	1168	8955	34
2002	8239	8239	477	15	7777	7777	7275	2025	200	9100	1167	8943	157
2003	8281	8281	512	15	7784	7784	7226	2087	0	9313	1168	8951	362
2004	8596	8596	477	16	8135	8135	7229	2326	0	9555	1220	9355	200
2005	8501	8501	477	0	8024	8024	7732	2064	200	9596	1204	9227	369
2006	9034	9034	487	0	8547	8547	7627	2773	82	10318	1282	9829	489
2007	9427	9427	352	0	9075	9075	7577	2951	345	10183	1361	10436	-254
2008	10302	10302	352	0	9950	9950	7432	3132	250	10314	1493	11443	-1129
2009	8749	8749	352	0	8397	8397	7561	2422	105	9878	1260	9656	222
2010	8826	8826	352	0	8474	8474	7562	2320	110	9772	1271	9745	27
2011	9315	9315	352	0	7938	7938	7497	1911	0	9408	953	8891	517
2012	9483	9483	352	0	8090	8090	7686	1896	0	9582	971	9060	522
2013	9621	9621	352	0	8219	8219	7819	1904	0	9723	986	9205	518
2014	9761	9761	352	0	8351	8351	7894	1945	0	9839	1002	9353	486
2015	9873	9873	352	0	8454	8454	7095	2609	0	9704	1015	9469	235
2016	9985	9985	352	0	8566	8566	7797	2320	0	10117	1028	9594	523
2017	10082	10082	352	0	8664	8664	7277	2834	0	10112	1040	9703	409
2018	10180	10180	352	0	8761	8761	6866	3180	0	10045	1051	9812	233
2019	10263	10263	352	0	8844	8844	7160	3077	0	10237	1061	9905	332
2020	10353	10353	352	0	8934	8934	6693	3562	0	10254	1072	10006	248
2021	10415	10415	350	0	8999	8999	6623	3756	0	10379	1080	10079	300
2022	10477	10477	350	0	9060	9060	6560	3825	0	10385	1087	10147	238
2023	10538	10538	350	0	9121	9121	6820	3723	0	10543	1095	10216	327
2024	10593	10593	350	0	9177	9177	6336	4179	0	10516	1101	10278	238
2025	10633	10633	0	0	9567	9567	7186	3510	0	10696	1148	10715	-19
2026	10685	10685	0	0	9618	9618	7256	3646	0	10902	1154	10772	130

NOTES :

1. Forecasted demand values based on a 50% forecast level with a DSM Adjustment and Load Management
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April.
3.Xcel continues to project accredited wind resources at 8% nameplate capacity.

Load and Generating Capacity Data Including Future Plants Needing a CON - WINTER

	Seasonal System Demand	Annual System Demand	Total Seasonal Firm Purchases	Total Seasonal Firm Sales	Seasonal Adjusted Net Demand	Annual Adjusted Net Demand	Net Generating Capacity	Total Participation Purchases	Total Participation Sales	Adjusted Net Capability	Net Reserve Capacity Obligation	Total Firm Capacity Obligation	Surplus or Deficit Capacity
2001	6557	8349	136	384	6805	8597	7534	1241	178	8596	1290	8095	502
2002	6221	8239	139	362	6444	8462	7491	1188	135	8544	1269	7713	831
2003	6386	8281	2	365	6749	8644	7738	1176	125	8789	1297	8045	743
2004	6653	8596	127	365	6891	8834	7718	1123	128	8713	1325	8216	497
2005	6873	8501	127	366	7112	8740	7718	1173	53	8838	1311	8423	415
2006	6833	9034	131	365	7067	9268	7936	1729	50	9615	1390	8457	1158
2007	7413	9427	2	350	7760	9775	7616	1982	50	9548	1466	9227	321
2008	7509	10302	2	350	7856	10650	7895	2124	50	9969	1598	9454	515
2009	6915	8749	2	350	7263	9096	7773	1931	50	9654	1364	8627	1027
2010	6893	8826	2	350	6216	9174	8368	1937	50	10254	1101	7317	2937
2011	7193	9315	2	350	6499	8638	7120	1953	0	9073	1037	7535	1538
2012	7312	9483	2	350	6610	8789	7211	1938	0	9149	1055	7665	1484
2013	7430	9621	2	350	6720	8919	7071	1946	0	9017	1070	7790	1227
2014	7559	9761	2	350	6840	9050	7131	1951	0	9082	1086	7926	1156
2015	7650	9873	2	350	6932	9154	6693	2259	0	8952	1098	8030	922
2016	7745	9985	2	350	7026	9266	7136	2491	0	9628	1112	8138	1490
2017	7836	10082	2	350	7117	9363	6504	2921	0	9425	1124	8240	1184
2018	7928	10180	2	350	7209	9461	6231	3119	0	9350	1135	8345	1006
2019	8017	10263	2	350	7298	9544	6453	3116	0	9569	1145	8443	1126
2020	8109	10353	2	350	7391	9634	5971	3575	0	9546	1156	8547	999
2021	8193	10415	0	350	7477	9699	5967	3699	0	9666	1164	8641	1025
2022	8279	10477	0	350	7562	9760	5832	3830	0	9662	1171	8733	929
2023	8364	10538	0	350	7648	9821	6041	3818	0	9859	1179	8826	1033
2024	8473	10593	0	350	7756	9877	5577	4242	0	9819	1185	8942	877
2025	8581	10633	0	0	7514	9567	7024	3825	0	10849	1148	8662	2187
2026	8581	10685	0	0	8581	9618	6917	4133	0	11050	1154	9735	1315

NOTES :

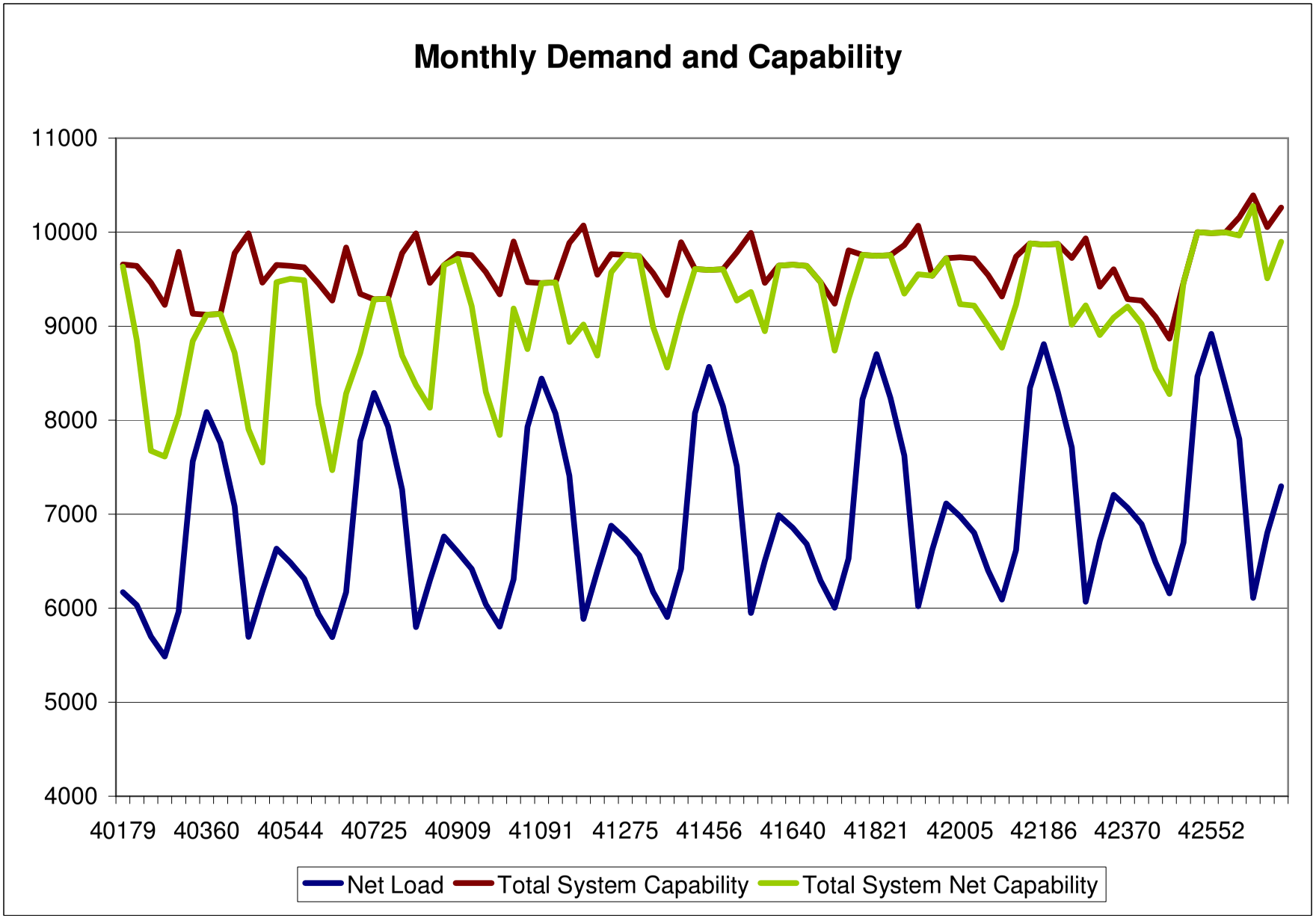
1. Forecasted demand values based on a 50% forecast level with a DSM Adjustment.
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April
3. Wind resources are included in net generating capacity. The only new wind resource is our 100 MW Grand Meadow facility which is included at nameplate as it is not accredited yet. Future wind resources were not included because at this point we have not determined the ownership versus PPA split. Xcel continues to project accredited wind resources at 13.5% nameplate capacity.
4. The future Manitoba Hydro purchase that begins in 2015 is included here. This resource does not technically need a CON, however, as part of the Track Two process it wil be subjected to the "CON-like" review process.
5. Xcel Energy will need additional resources in future years, the specific details will be addressed in future resource plans.

Additions

2011	2012	2013	2014	2015	2016	2017	2018
Nobles 16 MW	Generic Wind 8 MV	Generic Wind 8 MW	Generic Wind 8 MV	Generic Wind 8 MW	Generic Wind 8 MW	Generic Wind 8 MV	Generic Wind 8 MW
Wind 16 MW	Generic Wind 8 MV		PI EPU 6 70 MW	Manitoba Hydro 375	EPU_Del 6 70 MW	MH Diveristy 200 M	
	Sherco 3 13 MW			MH Diversity 150 MV	Black Dog Repowering		
	Wind 4 MW						
	Monti EPU 69 MW						
	Merricourt 12 MW						
	Wind 5 MW						
2019	2020	2021	2022	2023	2024	2025	2026
Generic Wind 8 MW	Generic Wind 8 MV	Manitoba Hydro Expa	Generic Wind 8 MV	Generic CT 195 MW	Generic Wind 8 MW	Generic Wind 8 MV	Generic Wind 8 MW
Generic CT 195 MW	Generic Wind 8 MV		Generic Wind 8 MV		Generic Wind 8 MW	Generic Wind 8 MV	Generic Wind 8 MW
	Generic CT 195 MV				Generic CT 195 MW	Generic CC 5 731	Generic Wind 8 MW
						Generic CT 195 MV	Generic CT 195 MW
						Generic CT 195 MV	Generic CT 195 MW
						Generic CT 195 MV	Generic CT 126 MW

Retirements

2011	2012	2013	2014	2015	2016	2017	2018
Cyprus 1 -40 MW		Key City 4 -13 MW	MNMethan -3 MW	Manitoba Hydro -50	Coyote 1 -100 MW	Rapidan -3 MW	Wilmarth 1 -20 MW
		Key City 3 -13 MW		MH Diversity -169 M	BlackDog 4 -164 MW	MH Diversity -225 MW	Redwing 1 -21 MW
		Key City 1 -13 MW			BlackDog 3 -89 MW		HERC -34 MW
		Granite 4 -13 MW					
		Granite 3 -13 MW					
		Granite 2 -13 MW					
		Granite 1 -13 MW					
		Flambeau 1 -14 MW					
2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
WSMorrn -4 MW	FlyngCld -5 MW		St.Cloud -7 MW	St. Paul 1 -25 MW	LkBnton1 -9 MW	Manitoba Hydro -500	PineBend -12 MW
Moraine -4 MW	Anson 3 -94 MW		LacCourt -3 MW	MNDakota -12 MW	Fch Isld 4 -61 MW	Invenerg 1 -301 MW	CalpMnkt 1 -319 MW
	Anson 2 -94 MW				Fch Isld 3 -61 MW	MH Diversity -350 MW	
					Fch Isld 1 -29 MW		
					Chanaram -7 MW		
					Bayfront 6 -28 MW		
					Bayfront 5 -22 MW		
					Bayfront 4 -22 MW		


Monthly Demand and Capability
11000
10000
9000
8000
7000
6000
5000
4000
40179
40360
40544
40725
40909
41091
41275
41456
41640
41821
42005
42186
42370
42552
Net Load
Total System Capability
Total System Net Capability

Appendix B
Additional Information Regarding Alternative Generating Facilities

Generation Alternatives Operational Information Summary

Item from Minnesota Rules 7849.0320	Repowering	Combustion Turbines
Capacity	About 700 MW	781 MW
Annual Capacity Factor	35%	4%
Typical Availability	> 90%	> 90%
A. Land Requirements	No new land, 35 acres reused on existing site	10 acres per combustion turbine, 40 acres total
B. Traffic: Ongoing and Construction	Ongoing: Reduction as only 15 people needed for new plant Construction: Equipment deliveries, construction worker traffic and an estimated 30,000 trucks for site fill delivery.	Ongoing: Minimal additional traffic 4-6 individuals are estimated for full time staff Construction: Equipment deliveries and construction workforce traffic will be temporary.
E. Water Use: Max. Pumping Rate	Groundwater: 250 GPM (existing plant site) Surface Water: 447 cubic feet per second	Maximum of 125 GPM ground water No surface water used
Annual Appropriation	Groundwater: 17 MG per year or 51 acre-feet	2.4 MG per year of groundwater for evaporative cooling at 4% capacity factor or 7.4 acre-feet 4.9 MG per year for water injection when using fuel oil combustion at 0.5% capacity factor or 15.1 acre-feet
Annual Consumption	Surface Water: 215,100 acre-feet per year (once thru cooling)	No surface water used for cooling
F. Discharges to Water	70,600 MG per year (refer to table 4-6 for details)	0.6 MG per year to sanitary sewer for evap cooler blowdown and water treatment (R/O) reject water 1.6 MG per year to sanitary sewer for R/O reject water related to water injection for fuel oil combustion
G. Radioactive Releases	None	None
H. Solid Wastes Produced	Refer to table 6.4	Maintenance materials less than 10 tons/year

Item from Minnesota Rules 7849.0320	Repowering	Combustion Turbines
I. Noise	Potential sources include CT inlets, exhaust stacks and vents. Inlets and exhaust stacks will be equipped with silencers and site will meet MN rules.	Potential sources include CT inlets, exhaust stacks and vents. Inlets and exhaust stacks will be equipped with silencers and site will meet MN rules.
J. Work Force	15 permanent employees 300 construction workers	4-6 permanent employees 75 construction workers per combustion turbine
K. Transmission Requirements	New 345 kV interconnect and substation	115 kV or 345 kV interconnection depending on specific location

Generation Alternatives Fuel Information

Item from Minn. R. 7849.0320	Repowering	Combustion Turbines
Capacity	About 700 MW	781 MW
Fuel Type	Natural Gas	Natural Gas
C (1). Fuel Source	Natural Gas Pipelines, Northern Natural, CenterPoint, others	Natural Gas Pipelines, Northern Natural, CenterPoint, others
Fuel Type	N/A	Fuel Oil (Backup)
C (1). Fuel Source		Fuel Oil: Flint Hills, Marathon, others
C (2). Fuel Requirement • Winter Peak • Annual Use		Fuel Oil 884 MW – 64,500 gallons/hour 2.8 million gallons/year at 0.5% capacity factor
Efficiency (HHV) • Winter Peak		884 MW – 33.6% efficiency
C (3). Heat Input (HHV) • Winter Peak		8,966 million BTU/hour
C (4). Higher Heat Value		139,000 BTU/gallon
C (5). Fuel Composition (a.) Sulfur (b) Ash (c) Moisture		0.0015 lb/MMBTU 0.01 Percent < 0.02 Percent

Estimated Air Emissions of Generation Alternatives at Rated Capacity

Estimated Emission Rates (lbs./MWh)			
	Repowering	Combustion Turbines	Combustion Turbines
Fuel Type	Natural Gas	Natural Gas	Fuel Oil
Pollutant			
SO_2	0,0076	0.0099	0.0161
NO_X	0.1263	0.3234	1.6759
PM_{10}	0.0575	0.0852	0.1543
Trace Elements (Lead and Mercury)	0.0000031	0.0000040	0.0000170

Strategist Assumptions

Unit	Maximum Capacity (MW)	July Accredited Capacity (MW)	Retirement Date	First Year Available
***COAL 0**				
AS King 1	510.0	510.0	2049	
BlackDog 3	89.0	89.0	2015	
BlackDog 4	164.0	164.0	2015	
Sherco 1	697.0	697.0	2049	
Sherco 2	682.0	682.0	2049	
Sherco 3	521.0	521.0	2049	
***NUCLEAR 0**				
Monti 1	587.0	564.0	2029	
P Island 1	546.0	521.0	2033	
P Island 2	546.0	518.7	2034	
***BIOMASS 0**				
Bayfront 4	22.0	22.0	2023	
Bayfront 5	22.0	22.0	2023	
Bayfront 6	28.0	28.0	2023	
Fch Isld 12	29.0	29.0	2023	
Redwing 12	21.0	21.0	2017	
Wilmarth 12	20.0	20.0	2017	
St. Paul 1	25.0	25.0	2023	
VirgHibb 1	35.0	35.0	2026	
Fibromin 1	50.0	50.0	2028	
***GAS CTs 0**				
Anson 2	120.0	94.0	2019	
Anson 3	120.0	94.0	2019	
Anson 4	181.0	158.0	2035	
Bluelake 7	180.0	155.0	2035	
Bluelake 8	180.0	155.0	2035	
Flambeau 1	18.0	14.0	2012	
Granite 1	16.0	13.0	2013	
Granite 2	16.0	13.0	2013	
Granite 3	16.0	13.0	2013	
Granite 4	16.0	13.0	2013	
Inverhil 1	62.0	47.0	2027	
Inverhil 2	62.0	47.0	2027	
Inverhil 3	62.0	47.0	2027	
Inverhil 4	62.0	47.0	2027	
Inverhil 5	62.0	47.0	2027	
Inverhil 6	62.0	47.0	2027	
Key City 1	16.0	13.0	2013	
Key City 2	0.0	0.0	2013	
Key City 3	16.0	13.0	2013	
Key City 4	16.0	13.0	2013	
Wheaton 1	62.0	47.0	2035	
Wheaton 2	70.0	55.0	2035	
Wheaton 3	62.0	47.0	2035	
Wheaton 4	62.0	47.0	2035	
Invenerg 1	358.0	300.9	2025	

Strategist Assumptions

***GAS CCs 0**				
BlkDg CC 52	315.0	283.0	2032	
HB_CC 1	575.0	495.0	2049	
RS_CC 1	511.0	484.0	2049	
LSCotGrv 1	275.0	244.2	2027	
CalpMnkt 1	375.0	319.0	2025	
BLKDG CC 67			2049	2016
***OIL 0**				
Bluelake 1	52.0	40.0	2030	
Bluelake 2	52.0	40.0	2030	
Bluelake 3	52.0	40.0	2030	
Bluelake 4	59.0	47.0	2030	
Fch Isld 3	81.0	61.0	2023	
Fch Isld 4	81.0	61.0	2023	
Wheaton 5	70.0	52.0	2035	
Wheaton 6	70.0	52.0	2035	
InvrD78 78	5.0	4.0	2049	
Diesels 1	7.5	6.0	2049	
***PURCHAS 1**				
Cyprus 1	40.0	40.0	2011	
Coyote 1	100.0	100.0	2015	
***GENERIC 0**				
225_CT 1	223.0	195.0	2049	2015
812_CC 1	812.7	731.0	2049	2017
1000_Nuc 1	1000.0	960.0	2049	2026
IGCCwSEQ 1	515.0	437.0	2049	2020
SCPCwSEQ 1	511.0	485.0	2049	2022

Strategist Assumptions

Unit	Maximum Capacity (MW)	July Accredited Capacity (MW)	Annual Energy (GWh)	Retirement Date	First Year Available
Barron	0.00	0.00	0.13	2049	
FlyngCld	4.60	4.60	0.40	2019	
HERC	33.70	33.70	215.40	2017	
MNMethan	3.10	3.10	14.45	2014	
PineBend	12.00	12.00	49.24	2026	
RARH	12.00	12.00	89.35	2028	
***HYDRO**					
Byllesby	2.60	2.60	10.59	2028	
EauGalle	0.30	0.30	1.19	2026	
Hastings	3.30	3.30	23.15	2033	
LacCourt	3.10	3.10	3.95	2021	
Neshonoc	0.40	0.40	2.15	2019	
Rapidan	2.80	2.80	19.79	2017	
St.Cloud	6.70	6.70	43.30	2021	
***MANTOBA**					
MH500	500.00	500.00	2085.71	2015	
Div150In	169.00	169.04	132.48	2014	
Div200In	225.00	225.38	176.64	2016	
Div150Out	-150.00	0.00	0.00	2015	
Div200In	-200.00	0.00	0.00	2016	
MH375500	375/500	375/500	1292/1749	2025	2015
DIV385In	350.00	350.00	0.00	2025	2015
DIV385Out	350.00	0.00	0.00	2025	2015

Strategist Assumptions

*WIND					
WoodStck	10.20	0.82	25.08	2034	
Lakota	11.25	0.90	27.67	2034	
NAEShaok	11.88	0.95	37.07	2034	
Velva	11.88	0.95	31.21	2026	
CommWind	60.00	4.80	205.14	2030	2011
Ewington	19.95	1.60	60.02	2028	
GrantCo	20.00	1.60	56.51	2028	
WindPowr	25.00	2.00	61.48	2019	
Jeffers	50.00	4.00	150.43	2027	
Moraine	51.00	4.08	159.12	2018	
Chanaram	85.50	6.84	268.30	2023	
FPL Mowr	98.90	7.91	323.47	2026	
LkBnton1	107.25	8.58	263.74	2023	
LkBnton2	103.50	8.28	311.39	2030	
MNDakota	150.00	12.00	512.85	2022	
Fenton	205.50	16.44	702.61	2032	
GrandMed	100.50	8.04	335.47	2033	
09_RFP	198.25	15.86	596.75	2030	2011
ND_50	50.00	4.00	181.40	2031	2012
Nobles	201.00	16.08	720.68	2035	2011
Merricou	150.00	12.00	544.19	2036	2012
NthShaok	13.53	1.08	35.54	2033	
Ruthton	15.84	1.27	47.66	2031	
WVarious	16.34	1.31	55.87	2031	
WSJJN	1.50	0.12	5.13	2031	
Garmcn	27.50	2.20	67.58	2028	
WSGarmcn	9.25	0.74	22.73	2021	
Viking	12.00	0.96	39.25	2018	
Westridg	7.60	0.61	23.85	2028	
Stahl	8.25	0.66	25.74	2025	
WSWstrdg	9.50	0.76	29.81	2028	
Eastridg	10.00	0.80	24.59	2026	
MNWind	11.55	0.92	36.04	2025	
Tholen	13.20	1.06	45.13	2025	
Norgaard	8.75	0.70	22.98	2026	
WSMorrn	49.50	3.96	154.44	2019	
Cisco	8.00	0.64	21.01	2028	

Strategist Assumptions

Unit	Annual Energy (GWh)	July Accredited Capacity (MW)
AppleRiv 1	14.611	1.29
BigFalls 1	36.146	3.44
CedarFls 1	33.596	3.01
Chippewa 1	65.600	10.32
Cornell 1	83.029	14.19
EauClare 1	41.693	3.44
Hayward 1	1.462	0.43
HennIsld 1	69.175	4.73
Holcombe 1	94.324	15.48
JimFalls 1	109.941	24.51
Ladysmth 1	10.341	1.29
Menomoni 1	22.918	2.58
Riverdal 1	3.095	0.86
SaxonFls 1	10.323	0.86
St.Croix 1	114.365	10.32
Superior 1	11.721	0.86
Thornapl 1	8.245	0.86
Trego 1	7.326	0.86
WhiteRiv 1	4.688	0.86
Wissota 1	134.120	15.48

Strategist Assumptions

Generic Wind (Max Capacity in MW)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
WIND_PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
WIND_PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
WIND_PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100
WIND_PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100
WIND_PPA	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100
WIND_PPA	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100
WIND_PPA	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100
WIND_PPA	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100
WIND_PPA	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100
WIND_PPA	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100
WIND_PPA	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100
WIND_PPA	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100
WIND_PPA	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100
WIND_PTC	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
WIND_PTC	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100
WIND_PTC	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100
WIND_PTC	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Total	**0**	**0**	**200**	**300**	**400**	**500**	**600**	**700**	**800**	**900**	**1100**	**1100**	**1300**	**1300**	**1500**	**1700**

* Accredited Capacity for wind is 8%

Strategist Assumptions

System Rates	
Composite Tax Rate	40.74%
Federal Income Tax Rate	35%
Inflation Rate	1.90%
Real Discount Rate	5.55%
Utility Discount Rate	7.56%
Weighted Cost of Capital	7.56%
Capital Project Rates	
AFUDC Rate	7.70%
Debt Structure Rate	46.17%
Desired Return on Rate Base	8.83%
Insurance Rate	0.04%
Long Term Debt Interest Rate	6.56%
Property Tax Rate	1.67%
Escalation Rates	
Labor	2.56%
NonLabor	1.60%
Weighted	1.90%
L25C75	1.84%
L50C50	2.08%
L75C25	2.32%
4 Prct	4.00%
3 Prct	3.00%
2 Prct	2.00%
5 Prct	5.00%
6 Prct	6.00%
7 Prct	7.00%
1Prct	1.00%

Strategist Assumptions

	Weighted Average Fule Price ($/mmBtu)					
	Coal	Gas	Nuke	Oil	Biomass	RDF
2010	$1.87	$4.51	$0.81	$15.58	$2.76	$0.20
2011	$1.98	$4.48	$0.83	$16.76	$2.84	$0.20
2012	$2.06	$4.83	$0.87	$17.62	$2.93	$0.20
2013	$2.15	$5.21	$0.89	$19.72	$3.01	$0.20
2014	$2.25	$5.77	$0.94	$20.84	$3.10	$0.21
2015	$2.33	$6.55	$1.00	$21.65	$3.20	$0.21
2016	$2.37	$6.86	$1.02	$22.19	$3.29	$0.22
2017	$2.43	$7.00	$1.04	$23.01	$3.39	$0.23
2018	$2.47	$7.15	$1.06	$23.75	$3.49	$0.23
2019	$2.52	$7.49	$1.08	$24.07	$3.60	$0.24
2020	$2.58	$7.81	$1.10	$24.53	$3.71	$0.25
2021	$2.63	$8.22	$1.12	$25.32	$3.82	$0.26
2022	$2.68	$8.66	$1.14	$25.94	$3.93	$0.26
2023	$2.74	$8.93	$1.17	$26.18	$4.05	$0.27
2024	$2.78	$8.89	$1.19	$26.78	$4.17	$0.28
2025	$2.84	$9.27	$1.21	$27.36	$4.30	$0.29

Appendix C
Xcel Energy Demand Side Management ("DSM") Programs

Minn. R. 7849.0290 requires that an application for a Certificate of Need include information regarding the applicant's conservation and load management programs (collectively, "Demand Side Management" or "DSM"). This information is presented below for Xcel Energy.

Minn. R. 7849.0290 requires that an application must include:

A. The name of the committee, department, or individual responsible for the applicant's energy conservation and efficiency programs, including load management;

Lee Gabler, Director, Energy Efficiency Marketing is responsible for Xcel Energy's demand-side management (conservation and load management) programs.

B. A list of the applicant's energy conservation and efficiency goals and objectives;

Xcel Energy's[1] approved 2010-2012 Triennial Plan[2] represents a budget of over $240 million, energy savings of 1,116 GWh and demand savings of 315 MW over the three years.

C. A description of the specific energy conservation and efficiency programs the applicant has considered, a list of those that have been implemented, and the reasons why the other programs have not been implemented;

Xcel Energy is required under Minn. Stat. § 216B.241, Subd. 1a to spend at least 2% of its electric gross operating revenue ("GOR") on electric conservation programs and 0.5% of its gas GOR on gas conservation programs. Additionally, the Next Generation Energy Act of 2007 requires utilities, beginning in 2010, to have an annual energy savings goal equivalent to 1.5% of gross annual retail sales, unless modified by the Commissioner. The minimum energy savings goal is 1.0% of retail sales.

To comply with the minimum spending requirement, Xcel Energy offers an extensive portfolio of programs. In general, these programs can be categorized as direct or indirect. Further, the direct programs can be categorized as prescriptive or custom.

---

[1] Northern States Power Company, a Minnesota Corporation.
[2] Docket No. E,G002/CIP-09-198

Direct programs result in quantifiable energy savings. The Lighting Efficiency program, for example, offers rebates for the installation of energy efficient lighting within our business customer segment. Prescriptive programs use technical assumptions based on stipulated or deemed technical assumptions that are assigned to measures in order to calculate gross energy and demand savings. The rebates and savings are predetermined based on the deemed technical assumptions. Custom programs use technical assumptions that are specific to the actual measure characteristics in order to calculate the energy and demand savings. The rebates and savings vary with the measure. Further, direct programs can be categorized as conservation or load management programs. Load management programs are specifically designed to manage peak load.

The following table lists our program offerings over the last ten years. Please note that some of the programs have been discontinued, modified or incorporated into other programs.

1.1.1.1 Business Segment
Conservation
Commercial Heating Efficiency f.k.a. Boiler Efficiency
Commercial Real Estate
Compressed Air Efficiency
Commercial Audit and Contract Management
Computer Efficiency
Cooling Efficiency
Custom Efficiency
Data Center Efficiency
Distributed Generation Incentive
Efficiency Controls
Energy Assets
Energy Design Assistance (EDA)
Energy Design Assistance - Business New Construction
Energy Efficient Buildings – Business New Construction
Energy Efficient Rebate
Energy Management Systems
Food Service
Furnace Efficiency

Government Conservation
Heat Recovery Rebate
Industrial Efficiency
Lighting Efficiency
Market Transformation – Computer Efficiency
Market Transformation – Vending Efficiency
Motor & Drive Efficiency f.k.a Motor Efficiency
Process Efficiency
Recommissioning
Refrigeration Efficiency
Roofing Efficiency
Segment Efficiency
Load Management
Electric Rates Savings f.k.a Peak Controlled Rates
Business Saver's Switch
Indirect Impact
Business Education
Energy Advisory Service
Energy Analysis
Energy Financing
Lamp Recycling
School Financing
Turn Key Services
1.1.1.2 <u>Residential Segment</u>
Conservation
Central AC Quality Installation
ENERGY STAR Homes
ENERGY STAR Rebates
Energy Efficiency Showerheads f.k.a High-Efficiency Showerheads
Home Efficiency
Home Lighting Direct Purchase
Home Performance with ENERGY STAR
Insulation Rebate Program
Refrigerator Recycling
Residential Cooling
Residential Quick Fix Efficiency Service
Premier Home

School Education Kits
Water Heater Rebates
Load Management
Residential Saver's Switch
Indirect Impact
Consumer Education
Energy Loans
Home Energy Audits
Lamp Recycling
1.1.1.3 Energy Efficiency Support Services
1.1.1.4 Low-Income Segment
Conservation
Conservation Kits
Home Electric Savings
Low Income Weatherization
Residential Quick Fix – Low Income
Research, Evaluation & Pilots
Annex 49 Pilot
Energy Feedback Pilot

For more details on our current business, residential and low-income programs, see the Xcel Energy website at http://www.xcelenergy.com.

Xcel Energy's Product Development department continually analyzes potential measures and concepts to add to our program portfolio offering. Measures and programs are analyzed and prioritized based on cost-effectiveness standards, availability potential within the marketplace and applicability potential within our customer base.

D. A description of the major accomplishments that have been made by the applicant with respect to energy conservation and efficiency

The 2010-2012 CIP Triennial Plan continues Xcel Energy's long-standing commitment to DSM. Although DSM activities in many states around the country have ebbed and flowed, Minnesota and Xcel Energy as its largest utility have generally maintained a consistent approach to DSM. This long-standing commitment and dedication to excellence in running cost effective

conservation and load management programs places the Company among the nation's top utilities in terms of energy and demand saved and most innovative programs.

Between 1992 and 2009, Xcel Energy has invested over $805 million (nominal) resulting in 4,860 GWh of electric energy savings, 2,160 MW of electric demand savings and an estimated 9,3 million MCF of natural gas savings (since 1995). The total electric energy savings from 1992 to 2009 is equivalent to avoiding the cost of over eight 250 MW power plants. The following figures show our historical spending on CIP and energy savings achievements. Approved goals for 2010, 2011 and 2012 are provided for context.

Figure 1: CIP Electric Expenditures, 2000-2012

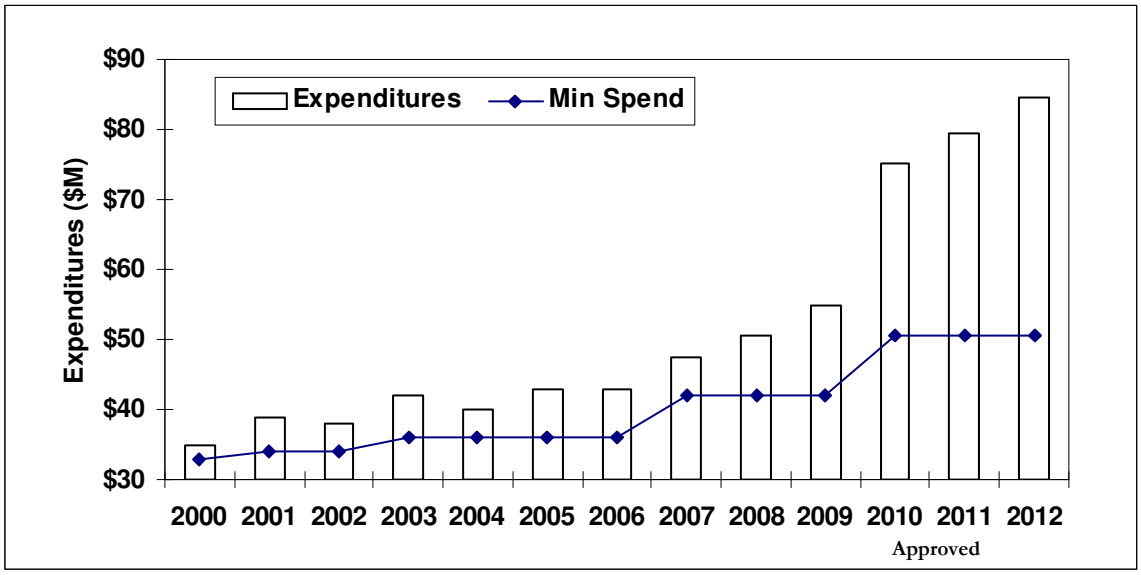


Figure 2: CIP Gas Expenditures, 2000-2012

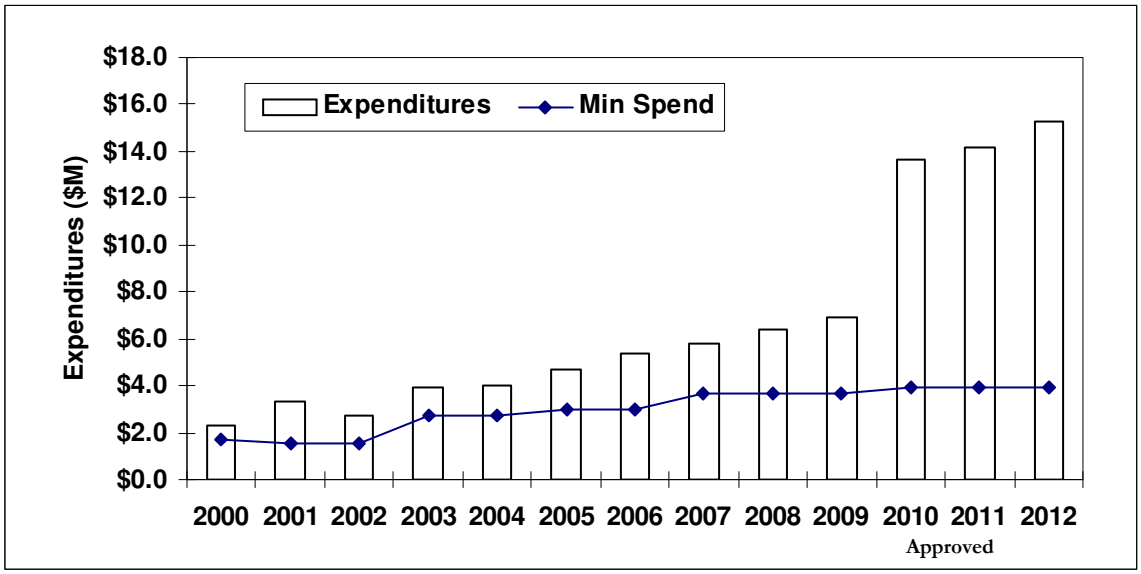


Figure 3: CIP Electric Energy Savings, 2000-2012

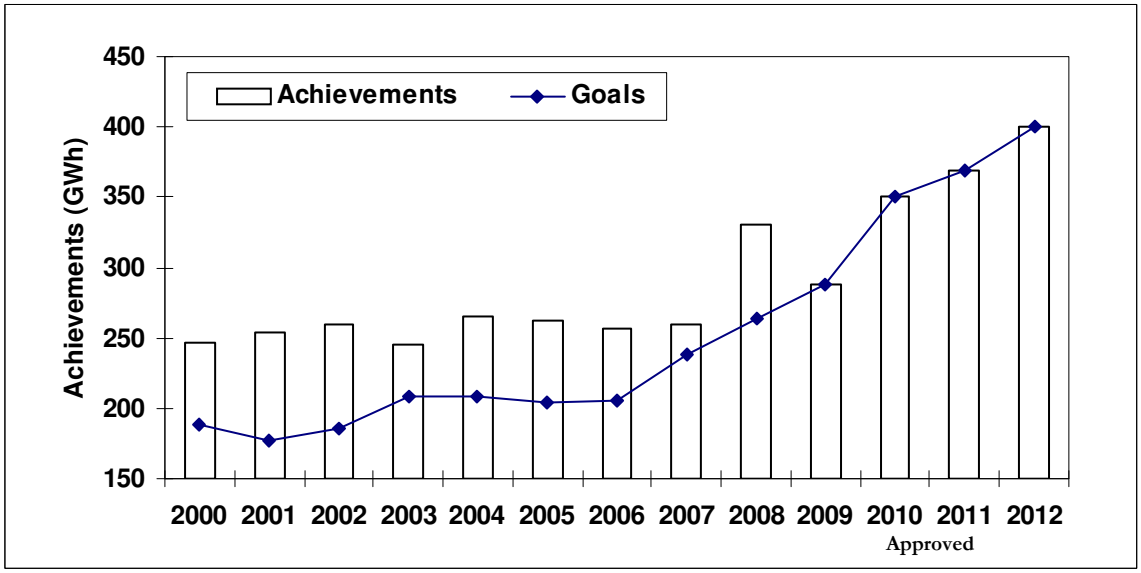


Figure 4: CIP Electric Demand Savings, 2000-2012

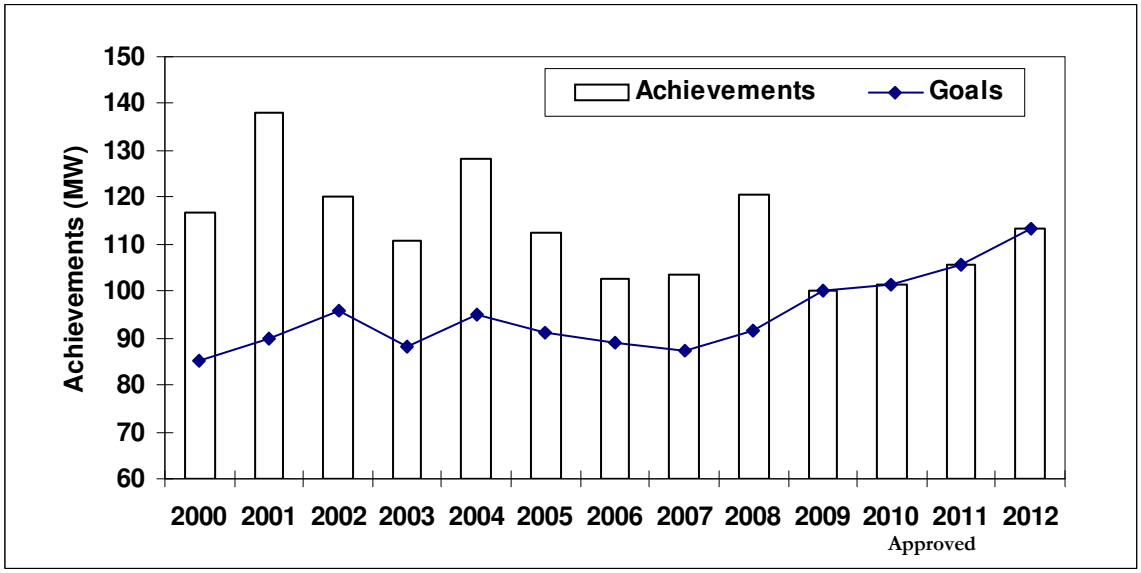
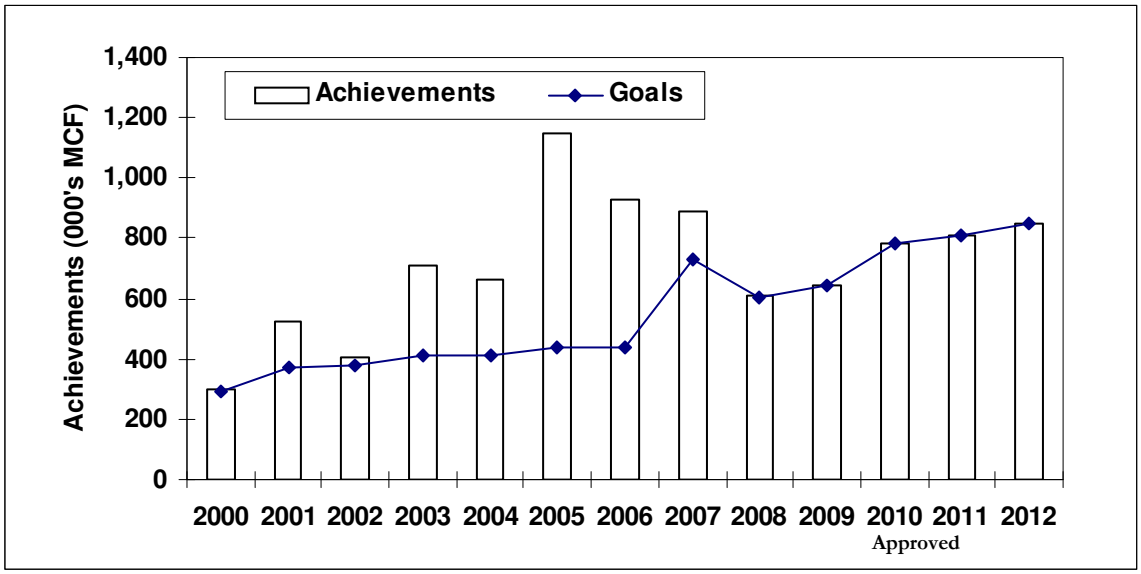


Figure 5: CIP Natural Gas Savings, 2000-2012



E. A description of the applicant's future plans through the forecast years with respect to energy conservation and efficiency

On August 5, 2009, the Commission approved our immediate (2010-2012) plans for DSM through our 2008-2022 Resource Plan[3]. Due to the significantly higher goals required from The Next Generation Act of 2007, we proposed to ramp our goals up by 2013 to our highest energy savings potential levels. The table below illustrates our proposed energy and demand savings from 2010-2025. On August 2, 2010, we filed our 2011-2025 Resource Plan. In that plan, we were required to model higher energy savings scenarios, as requested by intervenors. We did investigate scenarios where we targeted savings goals higher than 1.5%, we did not find sufficient program and cost information to enable us to develop a higher scenario. Our current scenarios already include far-reaching assumptions on where savings beyond our current programs will materialize. Moving to the next level of savings may involve adoption of technologies that are not yet commercial.

The table below shows DSM energy and demand savings levels as proposed in our 2011-2025 Resource Plan.

[3] Docket No. E-002/RP-07-1572

Current and Proposed Energy Efficiency Goals
At the Generator

Year	2008-2022 Plan	2008-2022 Plan	1.3% Scenario	1.3% Scenario	1.3% Scenario	1.5% Scenario	1.5% Scenario	1.5% Scenario
	Approved Demand Goal MW	Approved Energy Goal GWh	Demand Goal MW	Energy Goal GWh	Proposed Budget (millions)	Demand Goal MW	Energy Goal GWh	Proposed Budget (millions)
2008	47	260						
2009	49	264						
2010	114	358						
2011	123	374	63	367	$81	63	367	$81
2012	127	405	70	399	$86	70	399	$86
2013	133	421	83	390	$106	93	450	$124
2014	130	421	80	390	$109	91	450	$127
2015	128	421	79	390	$112	90	450	$129
2016	140	437	80	401	$120	91	462	$143
2017	145	437	81	401	$125	92	462	$152
2018	148	437	81	401	$135	93	462	$168
2019	154	453	84	412	$149	97	475	$190
2020	169	453	87	412	$152	99	475	$200
2021	169	453	90	412	$155	102	475	$203
2022	175	468	96	420	$160	107	484	$213
2023			101	420	$167	113	484	$218
2024			108	420	$180	122	484	$234
2025			119	431	$190	133	497	$242
2008-2022 Total	**1,951**	**6,061**						
Avg Annual 2008-2022	**130**	**404**						
2011-2025 Total			**1,303**	**6,065**		**1457**	**6879**	
Avg Annual 2011-2025			**87**	**404**		**97**	**457**	

* The goals for 2011 and 2012 are from our approved 2010-2012 CIP Triennial Plan.

F. A quantification of the manner by which these programs affect or help determine the forecast provided in response to part 7849.0270, subpart 2, a list of their total costs by program, and a discussion of their expected effects in reducing the need for new generation and transmission facilities

Load forecasts are based on historical data. Therefore, the forecasted annual peak demand for electricity and annual energy consumed reflect the savings due to DSM programs that have been implemented in the past. Because load forecasts are based on historic load data, a certain amount of continued DSM is already included in the forecast. This "amount" is known as embedded DSM and is roughly equal to the average annual DSM achievements obtained during the historical years. Thus, the energy and demand savings as ordered in the Resource Plan are not fully reflected in the forecasts. However, the forecast does include the historical or embedded DSM amount.

The energy and demand goals proposed in the 2011 Resource Plan are fully reflected in the resource planning analysis that determines future generation needs. An estimate of the embedded DSM is added to the load forecast in Strategist to derive an estimate of peak and energy as if no DSM were going to be implemented in future years. Then the approved DSM goals are subtracted from the modified forecast to calculate net peak and energy forecasts. If embedded DSM were not added to the load forecast, DSM would be double counted and the forecasts would consistently be too low.

Below is a list of our approved 2010-2012 DSM programs including their individual budgets, energy and demand savings. Following the annual tables is a three year Triennial Plan roll-up.

2010 Program Costs and Impacts

Executive Summary Table - 2010

2010	Electric Participants	Electric Budget	Customer kW	Generator kW	Generator kWh	Gas Participants
Business Segment						
Commercial Heating Efficiency	0	0	0	0	0	347
Commercial Real Estate	55	$635,417	808	690	3,004,195	8
Compressed Air Efficiency	373	$2,067,507	3,860	3,659	26,321,602	0
Cooling Efficiency	206	$1,906,924	3,366	2,427	6,083,882	0
Custom Efficiency	128	$3,018,198	5,168	2,890	25,440,451	43
Data Center Efficiency	10	$713,796	1,022	1,100	7,689,482	0
Efficiency Controls	70	$1,304,328	2,280	741	16,090,860	21
Energy Design Assistance-Business New Construction	63	$4,455,564	6,876	6,868	25,186,059	9
Energy Efficient Buildings-Business New Construction	18	$362,504	766	765	2,915,863	9
Furnace Efficiency	0	$0	0	0	0	209
Lighting Efficiency	416	$2,721,510	5,491	5,033	20,000,014	0
Market Transformation - Computer Efficiency	23,251	$260,812	442	476	2,620,085	0
Market Transformation - Vending Efficiency	9	$41,700	54	52	497,439	0
Motor & Drive Efficiency	714	$2,902,950	5,761	4,820	30,574,217	0
Process Efficiency	101	$5,756,733	6,680	4,799	37,912,052	31
Recommissioning	101	$2,050,038	2,898	1,485	14,518,829	20
Business Segment Energy Efficiency Total	**25,514**	**$28,197,980**	**45,472**	**35,805**	**218,855,030**	**697**
Business Saver's Switch	1,164	$1,979,611	25,385	8,342	49,598	0
Electric Rate Savings	110	$627,550	25,000	12,610	887,589	0
Business Segment Load Management Total	**1,274**	**$2,607,161**	**50,385**	**20,952**	**937,187**	**0**
Business Education	13,323	$237,392	0	0	0	1,817
Energy Advisory Service	63	$98,679	0	0	0	7
Energy Analysis	275	$293,668	0	0	0	128
Lamp Recycling	30,146	$30,000	0	0	0	0
Turn-Key Services	0	$0	0	0	0	0
Indirect Business Subtotal	**43,807**	**$659,739**	**0**	**0**	**0**	**1,952**
Business Segment Total	**70,595**	**$31,464,880**	**95,857**	**56,757**	**219,792,217**	**2,649**
Residential Segment						
Energy Efficient Showerhead Program	1,500	$16,308	2,700	0	401,864	8,500
ENERGY STAR Homes	1,115	$394,908	314	181	1,385,005	654
Heating System Rebate	0	$0	0	0	0	5,500
Home Lighting	303,595	$3,509,559	57,804	5,075	68,613,308	0
Home Performance with ENERGY STAR	175	$177,142	305	111	316,614	175
Insulation Rebate Program	70	$26,282	247	0	245,291	930
Refrigerator Recycling	2,000	$407,608	468	283	2,394,060	0
Residential Cooling	10,000	$3,122,290	6,962	6,868	5,071,837	0
Residential Quick Fix Efficiency Service	2,700	$474,607	2,957	600	2,032,553	2,700
School Education Kits	10,000	$301,267	2,944	46	973,699	10,000
Water Heating Rebate	0	$0	0	0	0	1,050
Residential Segment Energy Efficiency Total	**331,155**	**$8,429,970**	**74,702**	**13,162**	**81,434,232**	**29,509**
Load Management Segment - Residential Saver's Switch	**21,000**	**$6,479,078**	**63,302**	**19,970**	**171,406**	**0**
Consumer Education	412,949	$726,144	0	0	0	363,498
Home Energy Audits	3,077	$363,363	0	0	0	2,030
Lamp Recycling	224,964	$181,980	0	0	0	0
Energy Efficiency Support Services	0	$443,940	0	0	0	0
Indirect Residential Subtotal	**640,990**	**$1,715,427**	**0**	**0**	**0**	**365,528**
Residential Segment Total	**993,145**	**$16,624,475**	**138,004**	**33,132**	**81,605,638**	**395,037**
Low Income Segment						
Home Electric Savings Program	2,599	$1,564,006	894	364	1,652,004	0
Low Income Quick Fix Efficiency Service	1,050	$233,630	1,150	233	825,250	1,050
Single Family Weatherization Program	0	$0	0	0	0	408
Low Income Segment Total	**3,649**	**$1,797,636**	**2,044**	**597**	**2,477,254**	**1,458**

2011 Program Costs and Impacts

Executive Summary Table - 2011

2011	Electric Participants	Electric Budget	Customer kW	Generator kW	Generator kWh	Gas Participants
Business Segment						
Commercial Heating Efficiency	0	0	0	0	0	357
Commercial Real Estate	0	$0	0	0	0	0
Compressed Air Efficiency	420	$2,532,898	4,666	4,424	31,667,218	0
Cooling Efficiency	229	$2,013,323	3,408	2,468	6,112,294	0
Custom Efficiency	154	$3,563,725	6,112	3,496	30,253,803	50
Data Center Efficiency	11	$776,592	1,226	1,319	9,227,378	0
Efficiency Controls	71	$1,390,655	2,313	752	16,320,729	24
Energy Design Assistance-Business New Construction	62	$4,895,586	6,846	6,839	25,078,607	8
Energy Efficient Buildings-Business New Construction	20	$399,225	851	851	3,239,848	10
Furnace Efficiency	0	$0	0	0	0	222
Lighting Efficiency	440	$2,893,031	5,773	5,297	21,000,018	0
Market Transformation - Computer Efficiency	25,125	$324,364	542	583	3,234,486	0
Market Transformation - Vending Efficiency	9	$41,800	54	52	497,439	0
Motor & Drive Efficiency	915	$3,442,944	6,911	5,785	36,626,728	0
Process Efficiency	101	$6,278,844	6,896	4,920	39,408,781	32
Recommissioning	108	$2,201,652	3,092	1,585	15,476,361	24
Business Segment Energy Efficiency Total	**27,664**	**$30,754,638**	**48,690**	**38,368**	**238,143,690**	**727**
Business Saver's Switch	1,164	$2,036,351	25,385	8,342	49,598	0
Electric Rate Savings	110	$640,838	25,000	12,610	887,589	0
Business Segment Load Management Total	**1,274**	**$2,677,189**	**50,385**	**20,952**	**937,187**	**0**
Business Education	13,323	$238,972	0	0	0	1,817
Energy Advisory Service	138	$153,738	0	0	0	15
Energy Analysis	295	$344,968	0	0	0	132
Lamp Recycling	31,653	$32,000	0	0	0	0
Turn-Key Services	8	$301,176	0	0	0	5
Indirect Business Subtotal	**45,417**	**$1,070,854**	**0**	**0**	**0**	**1,969**
Business Segment Total	**74,355**	**$34,502,681**	**99,075**	**59,320**	**239,080,877**	**2,696**
Residential Segment						
Energy Efficient Showerhead Program	1,500	$17,080	2,700	0	401,864	8,500
ENERGY STAR Homes	1,172	$418,384	333	192	1,465,518	687
Heating System Rebate	0	$0	0	0	0	5,500
Home Lighting	285,256	$3,297,562	54,313	4,768	59,194,774	0
Home Performance with ENERGY STAR	200	$209,690	340	121	345,415	200
Insulation Rebate Program	74	$27,511	259	0	257,555	977
Refrigerator Recycling	4,000	$789,924	936	565	4,788,120	0
Residential Cooling	11,001	$3,415,117	7,659	7,555	5,579,647	0
Residential Quick Fix Efficiency Service	3,000	$506,308	3,286	666	2,185,358	3,000
School Education Kits	20,000	$597,356	5,888	91	1,745,425	20,000
Water Heating Rebate	0	$0	0	0	0	1,050
Residential Segment Energy Efficiency Total	**326,203**	**$9,278,932**	**75,714**	**13,958**	**75,963,678**	**39,914**
Load Management Segment - Residential Saver's Switch	**21,000**	**$6,641,978**	**63,302**	**19,970**	**171,406**	**0**
Consumer Education	423,273	$751,839	0	0	0	373,085
Home Energy Audits	3,231	$372,262	0	0	0	2,088
Lamp Recycling	236,212	$194,913	0	0	0	0
Energy Efficiency Support Services	0	$374,240	0	0	0	0
Indirect Residential Subtotal	**662,716**	**$1,693,254**	**0**	**0**	**0**	**375,173**
Residential Segment Total	**1,009,919**	**$17,614,165**	**139,016**	**33,928**	**76,135,084**	**415,087**
Low Income Segment						
Home Electric Savings Program	2,451	$1,563,906	840	360	1,583,094	0
Low Income Quick Fix Efficiency Service	1,050	$233,730	1,150	233	811,427	1,050
Single Family Weatherization Program	0	$0	0	0	0	408
Low Income Segment Total	**3,501**	**$1,797,636**	**1,990**	**593**	**2,394,521**	**1,458**

2012 Program Costs and Impacts

Executive Summary Table - 2012

2012	Electric Participants	Electric Budget	Customer kW	Generator kW	Generator kWh	Gas Participants
Business Segment						
Commercial Heating Efficiency	0	0	0	0	0	357
Commercial Real Estate	0	$0	0	0	0	0
Compressed Air Efficiency	490	$2,980,895	5,648	5,355	38,005,065	0
Cooling Efficiency	279	$2,046,350	3,433	2,492	6,128,212	0
Custom Efficiency	176	$4,228,193	7,544	4,333	37,808,710	51
Data Center Efficiency	12	$840,397	1,430	1,539	10,765,275	0
Efficiency Controls	72	$1,395,084	2,346	762	16,550,599	27
Energy Design Assistance-Business New Construction	62	$5,015,614	7,166	7,158	26,247,910	8
Energy Efficient Buildings-Business New Construction	30	$568,796	1,277	1,276	4,859,771	11
Furnace Efficiency	0	$0	0	0	0	240
Lighting Efficiency	483	$3,105,707	6,373	5,836	23,250,018	0
Market Transformation - Computer Efficiency	30,375	$442,567	761	819	4,578,543	0
Market Transformation - Vending Efficiency	9	$41,900	54	52	497,439	0
Motor & Drive Efficiency	994	$3,807,662	7,734	6,476	41,017,202	0
Process Efficiency	108	$7,058,772	7,656	5,474	43,895,686	32
Recommissioning	110	$2,250,290	3,157	1,618	15,795,538	27
Business Segment Energy Efficiency Total	**33,199**	**$33,782,226**	**54,578**	**43,189**	**269,399,967**	**753**
Business Saver's Switch	1,164	$2,086,837	25,385	8,342	49,598	0
Electric Rate Savings	110	$654,098	25,000	12,610	887,589	0
Business Segment Load Management Total	**1,274**	**$2,740,935**	**50,385**	**20,952**	**937,187**	**0**
Business Education	13,323	$238,972	0	0	0	1,817
Energy Advisory Service	222	$219,866	0	0	0	24
Energy Analysis	304	$381,421	0	0	0	137
Lamp Recycling	33,235	$35,000	0	0	0	0
Turn-Key Services	9	$314,520	0	0	0	6
Indirect Business Subtotal	**47,093**	**$1,189,779**	**0**	**0**	**0**	**1,984**
Business Segment Total	**81,566**	**$37,712,940**	**104,963**	**64,141**	**270,337,154**	**2,737**
Residential Segment						
Energy Efficient Showerhead Program	1,500	$17,629	2,700	0	401,864	8,500
ENERGY STAR Homes	1,244	$470,611	367	211	1,617,498	736
Heating System Rebate	0	$0	0	0	0	5,500
Home Lighting	262,880	$3,038,893	50,052	4,394	50,859,734	0
Home Performance with ENERGY STAR	225	$215,979	367	124	363,231	225
Insulation Rebate Program	77	$28,856	272	0	270,556	1,026
Refrigerator Recycling	5,000	$994,336	1,171	706	5,985,151	0
Residential Cooling	12,000	$3,657,237	8,354	8,241	6,086,205	0
Residential Quick Fix Efficiency Service	7,500	$1,157,020	8,215	1,666	5,295,719	7,500
School Education Kits	20,000	$616,126	5,888	91	1,745,425	20,000
Water Heating Rebate	0	$0	0	0	0	1,050
Residential Segment Energy Efficiency Total	**310,426**	**$10,196,687**	**77,386**	**15,435**	**72,625,382**	**44,537**
Load Management Segment - Residential Saver's Switch	**21,000**	**$6,797,971**	**63,302**	**19,970**	**171,406**	**0**
Consumer Education	433,854	$775,640	0	0	0	382,912
Home Energy Audits	3,392	$386,062	0	0	0	2,192
Lamp Recycling	248,023	$205,260	0	0	0	0
Energy Efficiency Support Services	0	$385,510	0	0	0	0
Indirect Residential Subtotal	**685,269**	**$1,752,472**	**0**	**0**	**0**	**385,104**
Residential Segment Total	**1,016,695**	**$18,747,130**	**140,688**	**35,405**	**72,796,788**	**429,641**
Low Income Segment						
Home Electric Savings Program	2,451	$1,563,906	840	360	1,583,094	0
Low Income Quick Fix Efficiency Service	1,050	$233,730	1,150	233	798,878	1,050
Single Family Weatherization Program	0	$0	0	0	0	433
Low Income Segment Total	**3,501**	**$1,797,636**	**1,990**	**593**	**2,381,973**	**1,483**

2010-2012 Triennial Plan Program Summary

Three Year Summary	Electric Participants	Electric Budget	Customer kW	Generator kW	Generator kWh	Gas Participants
2010	1,103,869	$75,935,992	247,653	99,921	349,653,552	434,148
2011	1,124,284	$81,002,168	252,810	104,183	367,263,284	454,240
2012	1,138,319	$86,183,240	261,370	111,377	399,220,302	468,861
2010 - 2012 Total	**3,366,472**	**$243,121,400**	**761,833**	**315,481**	**1,116,137,138**	**1,357,250**

Notice Plan

Our Notice Plan outlines the efforts we are undertaking to make the public aware of the filing of the Petition for approval of the Black Dog Repowering Project. The Notice Plan also informs potential parties of the process that will be utilized for reviewing the proposals being considered, including the opportunity for comments on our proposed Black Dog Repowering Project as well as the opportunity to file Alternative Proposals to the Black Dog Repowering Project and the information that should be included in an Alternative Proposal.

The Notice Plan consists of the three components listed below. Copies of the actual and proposed press releases, Notifications, and Guidance documents are included in this appendix.

1. Press Releases
2. Notifications, and
3. Guidance Documents.

1. Press Releases

There are two press releases. The first (Appendix D-1a) is the March 15, 2011 press release announcing the Company's Project and the filing of the Company's Certificate of Need Application for the Black Dog Repowering Project. The second (Appendix D-1b) will be provided to the media listed in Table D-1 below once the Commission has established the process and timeline for the submission of alternative proposals. We are recommending that alternative proposals be filed by June 1, 2011 in the Certificate of Need Application.

Table D-1: Media Contacts

Print News Media	TV and Radio Media
Mega Watt Daily (AKA Platts)	Associated Press – Minneapolis
St. Paul Pioneer Press	KARE – TV
Minneapolis Star Tribune	KMSP – TV
Twin Cities Business Journal	KSTP – TV
Minnesota News Network	WCCO – TV
Dow Jones Newswires	WCCO – Radio
Platts Electric Power Newsletters	Minnesota Public Radio

Hydro Review Magazine	**Web Sites**
	Xcel Energy Web
	Dept. of Commerce – E-dockets

2. Notifications

The Company will provide two Notifications to potentially interested parties in addition to the press releases. Copies of the Notifications will be sent to all parties on the following Service Lists:

- 2004 Resource Plan (Docket E002/RP-04-1752),
- 2007 Resource Plan (Docket E002/RP-07-1572), and
- Petition for Approval of Power Purchase and Diversity Exchange Agreements with Manitoba Hydro (Docket E002/M-10-633).

The first Notification was made concurrent with the filing of this Application and included sending a copy of the 1 page summary of the filing to all parties (Appendix D-2a). A copy of the second Notification (Appendix D-2b) will be made once the Commission has established the process and timeline for the submission of alternative proposals.

3. Guidance Documents

The third component of the Notification Plan consists of the Guidance Documents. The guidance document lists the fundamental transaction concepts as well as information we are seeking from Alternative Proposals to ensure sufficient information to compare the Alternative Proposal(s) to the Black Dog Repowering Project. A copy is attached as Appendix D-3.

The Guidance document will be referenced in each of the Notifications and will be available to parties via the Application on e-Dockets and the Company's website.

NEWS RELEASE
Xcel Energy Media Relations
414 Nicollet Mall, 7th floor
Minneapolis, MN 55401
(612) 215-5300
www.xcelenergy.com

March 15, 2011

Xcel Energy announces plan to repower Black Dog plant

Coal-fired units would be replaced with natural gas-fired units

MINNEAPOLIS – Xcel Energy today asked Minnesota regulators to approve a certificate of need for a project to retire its last two coal-burning units (Units 3 and 4) at the Black Dog plant in Burnsville, Minn., and replace them with natural gas burning units. Units 1 and 2 were converted to natural gas combined-cycle operation in 2002.

"We propose to use the existing Black Dog plant site to meet our customers' energy needs in the most cost-effective way possible," said Judy Poferl, president and CEO of Northern States Power Co.-Minnesota, an Xcel Energy company. "Repowering this plant with state-of-the-art natural gas technology is more economical than any of the alternatives available to us, makes great use of an existing plant site and existing transmission resources and will help meet our customers' needs in an environmentally sound manner. The project presents a great opportunity to modernize our power supply in a way that takes advantage of Black Dog's unique location and the infrastructure that has developed there over time."

The repowering project calls for construction of a combined-cycle facility on the Black Dog site, separate from the main building. The new facility will include two combustion turbines, two heat recovery steam generators and a steam turbine generator located in what is now the plant's coal yard. Integrating combustion turbine and steam turbine technology provides an extremely efficient electricity production process. Combined-cycle technology is about 50 percent more efficient than the existing traditional steam plant. The project will include a new substation and connection to the on-site 345 kilovolt transmission lines. A higher capacity natural gas line will also be installed to serve the facility.

The proposed Black Dog repowering project would replace the remaining 253 megawatts of coal-fired generating capacity at the site with about 700 megawatts of natural gas-fired generation. The project will provide generating capacity that can ramp up and down quickly as demand for electricity changes or production from wind turbines fluctuates with wind speeds. In addition, replacing the coal burning units with natural gas-fired units will significantly reduce air emissions, including mercury, sulfur dioxide, nitrogen oxides, fine particulates and carbon dioxide.

- More -

Black Dog Plant Repowering – pg. 2 of 2

The Black Dog proposal requires review and approval by various state agencies, including the Minnesota Pollution Control Agency and Minnesota Public Utilities Commission. As part of the certificate of need process, independent power suppliers will have the opportunity to propose alternative developments.

If the Black Dog project is approved, site preparation could begin in 2012 and foundation construction could begin in 2013. The new natural gas powered facility is expected to cost approximately $600 million and is proposed to come on line in 2016. The project will employ an estimated 300 construction workers over the construction period.

Xcel Energy's Black Dog repowering project is similar to the company's Minnesota Metro Emissions Reduction Project, which led to repowering the High Bridge and Riverside plants from coal to natural gas and upgrades to the Allen S. King plant. Combined with the previous emissions reduction project, the conversion of the Black Dog plant supports the utility's overall goals to make strategic use of critical locations, expand generating capacity, keep rates reasonable and reduce emissions to meet environmental requirements.

The Black Dog plant has been generating power since 1952. By 1960 Black Dog was NSP's second largest base load plant. For more information visit: Black Dog Plant

---

Xcel Energy (NYSE: XEL) is a major U.S. electricity and natural gas company that provides a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers through its regulated operating companies in eight Western and Midwestern states. Company headquarters are located in Minneapolis. More information is available at www.xcelenergy.com

###

NEWS RELEASE
Xcel Energy Media Relations
414 Nicollet Mall
Minneapolis, MN 55401
(612) 215-5300
www.xcelenergy.com

April XX, 2011

Application initiates competitive acquisition process

MINNEAPOLIS – Northern States Power Co. - Minnesota, an Xcel Energy company, filed a certificate of need application March 15 seeking approval from state regulators to retire its last two coal-burning units at the Black Dog plant in Burnsville, Minn., and replace them with natural gas burning units.

The need for this project was identified in Xcel Energy's 2010 Resource Plan (Docket No. E002/RP-10-825). The contents of the application describe and support the company's plan to address future capacity needs to serve customers.

The certificate of need filing initiated a competitive resource acquisition process for generation resources established by the Minnesota Public Utilities Commission. Interested parties are invited to submit their own proposals as alternatives to the Black Dog project for consideration by the commission.

Alternative proposals are due to the commission by 4:30 p.m., June 1, 2011. A copy of the application can be viewed at www.xcelenergy.com under "Black Dog Repowering Project Certificate of Need Application". Appendix D of the application provides guidance on the information to be contained in alternative proposals.

Questions regarding the alternative review process and other procedural issues can be directed to Susan Mackenzie, commission liaison, 121 7th Place East, St. Paul, Minn. 55101, 651-201-2241, susan.mackenzie@state.mn.us. Questions regarding alternative proposal preparation can be directed to Rick Peterson, Xcel Energy resource planning analyst, 612-330-5831, or richard.d.peterson@xcelenergy.com.

Xcel Energy (NYSE: XEL) is a major U.S. electricity and natural gas company that provides a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers through its regulated operating companies in eight Western and Midwestern states. Company headquarters are located in Minneapolis. More information is available at www.xcelenergy.com.

###

NOTICE OF APPLICATION FOR A CERTIFICATE OF NEED, AND INITIATING A COMPETITIVE RESOURCE ACQUSITION PROCESS

____, 2011

Northern States Power Company, a Minnesota corporation ("Xcel Energy"), has filed an application for Certificate of Need ("Application") for the Black Dog Generating Plant ("Plant") Repowering Project ("Project") and the associated transmission necessary for the direct interconnection of the Project.

The Project consists of replacing the coal-fired generating Units 3 and 4 at the Black Dog Plant site with about 700 MW of gas fired, combined cycle, generation located in what is now the coal storage yard at the Plant. The total output of Black Dog Units 3 and 4 was summer rated at 253 MW in 2010. As part of the Project, these units will operate solely on natural gas starting in 2013 and be shut down in 2016 after the new combined cycle facility is placed in service.

A need for future resources and the potential for this Project was identified in Xcel Energy's 2007 Resource Plan (Docket No. E002/RP-07-1572). The Minnesota Public Utilities Commission's ("Commission") Order in the 2007 Resource Plan directed the Company to "Continue to investigate repowering at Units 3 and 4 of the Black Dog Plant. Xcel's investigation shall include specific plans and time lines for the repowering." Our investigation of this Project concluded that it would be in the best interests of our customers to pursue the Project as described above, and the Company included the Project in our Five Year Action Plan in our 2010 Resource Plan (Docket No. E002/RP-10-825).

On March 15, 2011, Xcel Energy filed an application for Certificate of Need for the Project. The Application initiates a competitive resource acquisition process for generation resources established by the Commission. The contents of the Application describe and support the Company's proposal for addressing future capacity and energy needs. Interested parties can submit their Alternative Proposals and intervene in the process. Alternative Proposals are due to the Commission by 4:30 pm on June 1, 2011. A copy of our Application can be viewed at www.xcelenergy.com/XXX under "Black Dog Repowering Project Certificate of Need Application". Appendix D-3 of the Application provides guidance on the information to be contained in Alternative Proposals.

Questions regarding the alternative review process and other procedural issues can be directed to the Commission's designated liaison, Susan Mackenzie, at 121 7th Place East, St. Paul, MN 55101, phone 651-201-2241, or susan.mackenzie@state.mn.us. Questions regarding alternative proposal preparation can be directed to Rick Peterson, resource planning analyst for Xcel Energy, at 612-330-5831, or richard.d.peterson@xcelenergy.com.

Alternative Proposal Guidance

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), has initiated a resource acquisition process (as described in Docket E002/RP-04-1752) to satisfy capacity needs in 2016. The resource need primarily results from growing customer demand for electricity. Xcel Energy has proposed a repowering project at the Company owned Black Dog Generating Facility to meet the identified need. A thorough description of our capacity deficit and the proposed Black Dog Repowering Project is included in our Certificate of Need application which has been filed with the Minnesota Public Utilities Commission ("Commission").

Under the Commission's resource acquisition process, interested parties may submit their own proposals as "Alternative Proposals" for consideration by the Commission and intervene in support of their proposals in a subsequent contested case proceeding. The Alternative Proposal content should be detailed enough that the Commission can effectively initiate the proceedings needed to review the Alternative Proposal along with the Company's Black Dog Repowering Project. The proposer must provide the information necessary for the Commission to evaluate the proposal using its public interest and Certificate of Need criteria. The procedural framework of the Commission's alternative resource acquisition process is described in our Certificate of Need Application.

The following Proposal Guidance chart and Transaction Fundamentals listed in the chart provides interested parties with general concepts and terms that are of interest to Xcel Energy and that will be taken into consideration in the Company's evaluation of any Alternative Proposals. To the extent that an Alternative Proposal deviates from the Transaction Fundamentals provided below, the proposer should include an explanation of the deviation, the reason(s) for the deviation and the pricing impact that would result if the ultimate transaction did and/or did not include the deviation.

Alternative Proposal Data	***Guidance***
Developer Experience and Qualifications	Include identification and description of the developer, including financial strength, experience, development plans for successfully completing transaction, identification of the selling party and connections between the developer and the seller.
In-service date	January 1, 2016 For unit-contingent proposals, the in-service date of the facility(s) are to correspond with the in service date of the Black Dog Repowering Project. Any in-service date different than the above will be evaluated accordingly and must include an explanation of the benefits/pricing of different in-service dates and transaction lengths. A proposed in-service date different than January 1, 2016 will be evaluated accordingly.
Capacity Amount	Ability to provide for up to need discussed in 2010 Resource Plan plus capacity of existing Black Dog Units 3 and 4. Capacity amounts that differ materially from this profile will be evaluated accordingly. Alternative Proposals should include an explanation of the capacity profile being offered and the benefits provided. Capacity must be of a type and quality to be acceptable under MISO's reserve sharing requirements.
Energy Amount	Variable and Dispatchable
Delivery	Capacity and energy shall be delivered to a point within the operational control of MISO. Delivery shall be on a firm transmission basis at no additional cost to Xcel Energy. Resource must be a Capacity Resource delivered to the NSP load as required in Module E of the MISO Tariff and MISO Business

Alternative Proposal Data	***Guidance***
	Practices Manual for Resource Adequacy.
Resource Type	System power and unit contingent proposals will be considered. Firmness and reliability of the product will be considered in the evaluation of an Alternative Proposal. Different resource types will require different considerations and contracting structures (i.e., tolling, non-tolling, system power, unit contingent, etc.)
Emissions and Carbon Dioxide	The seller shall be responsible for permitting all emissions from the resource(s) and all costs to obtain any allowances or credits, to meet obligations to deliver capacity and energy to Xcel Energy. Alternative Proposal should demonstrate its emissions profile, with sufficient detail to allow analysis. Seller shall be responsible for all costs attributable to any and all emissions of whatever nature and type except Xcel Energy shall be solely responsible for carbon dioxide emission costs (but not capital related costs) associated with the energy received from seller.
Capacity Pricing	Fixed or fixed escalation preferred. The following capacity pricing format is suggested: The monthly price for the capacity component of the sale shall be US $_____ per MW-month and shall be escalated by _____% annually on January 1st of each Contract Year, with such escalation to commence on _____. Please include a chart describing the prices, etc by year. Capacity pricing for unit-contingent proposals will be subject to availability adjustments to be negotiated consistent with Xcel Energy's model dispatchable PPA. As applicable, seller should consider separate prices and availability percentages for on-peak and off-peak months (with emphasis for availability during the on-peak months, defined as June, July, August and September). Seller will credit Xcel Energy 1.5% of the capacity payment for each 1% that the capacity available falls below the seller's guaranteed

Alternative Proposal Data	***Guidance***
	capacity availability. All proposals that Xcel Energy deems likely to result in a Capital Lease will be evaluated to estimate the cost impacts of capital lease accounting that may result from such a proposal.
Energy Pricing	Energy delivery profile and pricing must be proposed in the Alternative Proposal. Separate pricing for intermediate load energy and dispatchable peaking energy desired. Fixed or fixed escalation is preferred for intermediate energy. Provide sufficient detail as to any components of the energy price that is not fixed to allow analysis and cost adjustments for the purpose of calculating an equivalent fixed price energy component. For unit contingent proposals that do not provide a fixed price or fixed escalation rate and rely on natural gas, tolling is preferred. Transaction document must include fuel (solid fuel, gas, fuel oil) requirements, including required heat rate, availability, testing and consequences for use of excess fuel as well as natural gas supplier.
Other Payments	Payments required for any other product or service must be specified in the Alternative Proposal. These may include as applicable: variable operations and maintenance payments; start or schedule charges; dispatchability payments; and fuel related payments.
Scheduling Provisions	Proposal required to include generating plant specifications/operational considerations and limitations for (i) planned maintenance; (ii) dispatchability and ramp rates; (iii) expected and required minimum and maximum load; (iv) any limitations on operations (including considerations based upon ambient conditions).
Curtailments and excuses for reduced delivery	Proposal must specify all reasons and circumstances where reduction or curtailment of the supply of capacity and curtailment of energy delivery is to be allowed and the financial consequences for

Alternative Proposal Data	***Guidance***
	any such event. Scheduled outages and consequences for forced and unplanned outages must be defined in the transaction document.
Security for Performance	The Proposal must include sufficient information to evaluate the selling party's financial strength and credit quality. If the selling party does not maintain investment grade credit rating (unenhanced by third-party support and without negative outlook) Xcel Energy will require financial security for performance.
Conditions to performance	- Negotiation of mutually acceptable transaction documents (PPA or other structure). - Required corporate approvals of both parties to the transaction have been obtained. - Commission approval of the transaction has been obtained. - Other conditions as may be mutually agreed upon (seller to provide its contract contingencies (that must be met or waived) in its proposal).
Additional Considerations for Unit Contingent Proposals	The Proposal must include, as applicable: - A description of seller's site for its generating facility; including whether seller currently has possession of/title to the site; - Schedule/milestone dates for seller's receipt of all air, water, waste disposal, sound level and other major project permits; - Schedule/milestone dates for financing, engineering, construction and procurement for the facility, and the timely deployment of the facility; - Adequate and firm Interconnection and delivery arrangements (with associated firm dates) have been made within the MISO footprint (interconnection and delivery costs will be an important

Alternative Proposal Data	***Guidance***
	evaluation criteria); - All ancillary services and products belong to Xcel Energy without additional compensation; - A firm Commercial Operation Date ("COD") sufficient to commence deliveries by January 1, 2016; - All schedules/milestones, commercial operation and other applicable dates will include appropriate liquidated damages for seller caused delays; - Seller must identify the type and quantity of emissions and carbon dioxide associated with its generation. Emissions profile will be evaluated accordingly. Any allowances, offsets, or credits relating to carbon dioxide emissions belong to Xcel Energy at no additional cost; - Unless selling party maintains an investment grade credit rating (unenhanced by third–party support and without negative outlook), a security fund must be provided at a level of $125/kW to secure performance, consisting of letter of credit, parental guaranty (allowed only after COD) or cash collateral. Criteria for posting security, including adequate assurance, to be incorporated in transaction document; - As applicable, all renewable energy credits belong to Xcel Energy; - Facility insurance and indemnification requirements to be included in transaction document; - Operational dispatch and technical specifications and requirements will be included in the transaction document; - Cost of disposal of all byproducts and wastes relating to the construction, testing and operation of the unit belong to seller; - Defaults and remedies to be included in transaction document consistent with Xcel Energy's general terms and conditions; - Sale or change of control of the unit will require Xcel Energy's

Alternative Proposal Data	***Guidance***
	consent to be included in transaction document; and - General terms and conditions will be developed from Xcel Energy's model dispatchable power purchase agreement. For a copy of the model dispatchable power purchase agreement please contact Richard Peterson, resource planning analyst for Xcel Energy, at 612-330-5831, or richard.d.peterson@xcelenergy.com.
Indemnities, Liabilities and Damages	Mutual waiver of consequential, special and punitive damages. No limitation on benefit of the bargain damages; presence of such limitations will be evaluated accordingly. No limitation on third party indemnifications. Defaults and remedies to be negotiated consistent with Xcel Energy's model dispatchable PPA.
Taxes	Seller shall be solely responsible for any and all present or future taxes and other impositions relating to the construction, ownership or leasing, operation or maintenance of its facilities, any sales or ad valorem taxes, any taxes on the natural gas acquired by seller or any taxes on the products and services generated by seller and sold to Xcel Energy. Seller's prices will be inclusive of such taxes and impositions. Xcel Energy shall be solely responsible for sales and use taxes imposed with respect to its purchases from seller. Any pricing adjustment for new or additional taxes will be included in the evaluation.
Reservation of Rights	No binding legal obligations exist until a definitive transaction document has been approved and signed by authorized representatives of the parties and approved by the Commission. Seller to indicate when a contract must be signed by the parties and a date it must be subsequently approved by the Commission in order to meet seller's schedule for commercial operation.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR A CERTIFICATE OF NEED FOR THE BLACK DOG GENERATING PLANT REPOWERING PROJECT	DOCKET NO. E002/CN-11-184 **Petition**

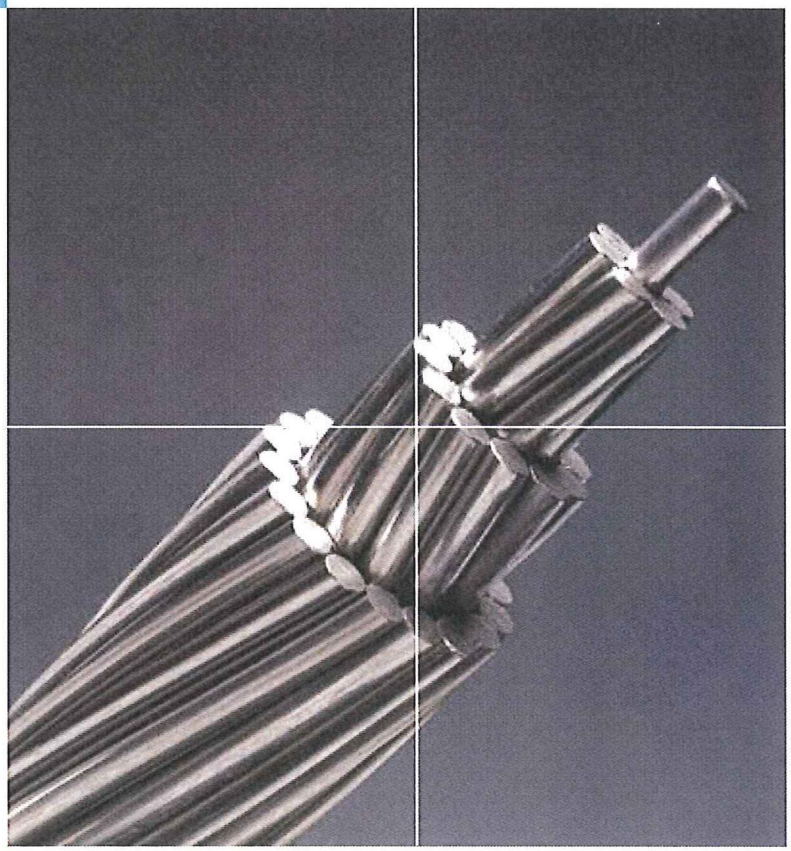
SUMMARY OF FILING

Please take notice that on March 15, 2011, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or "the Company"), filed with the Minnesota Public Utilities Commission ("Commission") an application for a Certificate of Need ("CON") for the Black Dog Generating Plant ("Plant") Repowering Project ("Project") and the associated transmission necessary for the direct interconnection of the Project.

The Project consists of replacing the coal-fired generating Units 3 and 4 at the Black Dog Plant site with about 700 MW of gas fired, combined cycle, generation located in what is now the coal storage yard at the Plant. The total output of Black Dog Units 3 and 4 was summer rated at 253 MW in 2010. As part of the Project, these units will operate solely on natural gas starting in 2013 and be shut down in 2016 after the new combined cycle facility is placed in service.

This filing also initiates the Alternative Competitive Resource Acquisition process established in Docket No. E002/RP-04-1752. Prospective alternative providers must intervene in support of their own proposal in a contested case proceeding.

Aluminum Conductor Steel Reinforced (ACSR) Cables



Alcan Cable manufactures a full line of ACSR cables which are used in overhead transmission and distribution line applications. Alcan offers various conductor designs and steel core coatings to address your application requirements.

Product Construction

ACSR is a concentric-lay-stranded conductor consisting of a single core wire or a stranded steel central core with one or more layers of 1350 H19 stranded aluminum wires. Steel core wires are protected from corrosion by galvanizing, aluminum-clad alloy or zinc – 5% aluminum mischmetal alloy coating. Standard, High, Extra and Ultra High strength steel are also available. All ACSR cables are also available in a non-specular finish.

Specifications

Alcan's ACSR cables meet or exceed industry requirements per ASTM specifications B230, B232, B498, and B500.

Product Features

ACSR conductors provide dependable performance for many years under adverse weather conditions. The combination of the aluminum and steel in the conductor design offer both efficient conductivity and high tensile strength making ACSR cable the most economical solution for overhead power transmission and distribution projects.

ACSR

Aluminum Conductor Steel Reinforced

ASTM: B230, Specification for Aluminum 1350-H19 Wire for Electrical Purposes
B232, Specification for Concentric-Lay-Stranded Aluminum Conductors, Coated Steel Reinforced (ACSR)
B498, Specification for Zinc-Coated (Galvanized) Steel Core Wire for Aluminum Conductors Steel Reinforced (ACSR)

Physical Properties

CODE WORD	SIZE AWG or kcmil	STRANDING Number & Diameter (In.) Aluminum	STRANDING Number & Diameter (In.) Steel	Nominal Diameter (In.) Complete Conductor	Nominal Diameter (In.) Steel Core	Rated Strength (Lbs.)	WEIGHT (Lbs./1000 Ft.) Total	WEIGHT (Lbs./1000 Ft.) Aluminum	WEIGHT (Lbs./1000 Ft.) Steel	PERCENT OF TOTAL WEIGHT Aluminum	PERCENT OF TOTAL WEIGHT Steel
TURKEY	6	6 x 0.0661	1 x 0.0661	0.198	0.0661	1190	36.0	24.4	11.6	67.8	32.2
SWAN	4	6 x 0.0834	1 x 0.0834	0.250	0.0834	1860	57.4	39.0	18.4	67.9	32.1
SWANATE	4	7 x 0.0772	1 x 0.1029	0.257	0.1029	2360	67.0	39.0	28.0	58.2	41.8
SPARROW	2	6 x 0.1052	1 x 0.1052	0.316	0.1052	2850	91.2	61.9	29.3	67.9	32.1
SPARATE	2	7 x 0.0974	1 x 0.1299	0.325	0.1299	3640	106.6	61.9	44.7	58.1	41.9
ROBIN	1	6 x 0.1181	1 x 0.1181	0.354	0.1181	3550	115.0	78.1	36.9	67.9	32.1
RAVEN	1/0	6 x 0.1327	1 x 0.1327	0.398	0.1327	4380	145.2	98.6	46.6	67.9	32.1
QUAIL	2/0	6 x 0.1489	1 x 0.1489	0.447	0.1489	5300	182.8	124.1	58.7	67.9	32.1
PIGEON	3/0	6 x 0.1672	1 x 0.1672	0.502	0.1672	6620	230.5	156.4	74.1	67.9	32.1
PENGUIN	4/0	6 x 0.1878	1 x 0.1878	0.563	0.1878	8350	290.8	197.4	93.4	67.9	32.1
WAXWING	266.8	18 x 0.1217	1 x 0.1217	0.509	0.1217	6880	289.1	249.9	39.2	86.4	13.6
PARTRIDGE	266.8	26 x 0.1013	7 x 0.0788	0.642	0.236	11300	366.9	251.3	115.6	68.5	31.5
MERLIN	336.4	18 x 0.1367	1 x 0.1367	0.684	0.1367	8700	364.8	315.3	49.5	86.4	13.6
LINNET	336.4	26 x 0.1137	7 x 0.0884	0.720	0.265	14100	462.0	316.5	145.5	68.5	31.5
ORIOLE	336.4	30 x 0.1059	7 x 0.1059	0.741	0.318	17300	526.4	317.7	208.7	60.4	39.6
CHICKADEE	397.5	18 x 0.1486	1 x 0.1486	0.743	0.1486	9900	431.0	372.5	58.5	86.4	13.6
IBIS	397.5	26 x 0.1236	7 x 0.0961	0.783	0.288	16300	546.0	374.1	171.9	68.5	31.5
LARK	397.5	30 x 0.1151	7 x 0.1151	0.806	0.345	20300	621.8	375.2	246.6	60.4	39.6
PELICAN	477	18 x 0.1628	1 x 0.1628	0.814	0.1628	11800	517.3	447.1	70.2	86.4	13.6
FLICKER	477	24 x 0.1410	7 x 0.0940	0.846	0.282	17200	613.9	449.4	164.5	73.2	26.8
HAWK	477	26 x 0.1354	7 x 0.1053	0.858	0.316	19500	655.3	448.9	206.4	68.5	31.5
HEN	477	30 x 0.1261	7 x 0.1261	0.883	0.378	23800	746.4	450.4	296.0	60.4	39.6
OSPREY	556.5	18 x 0.1758	1 x 0.1758	0.879	0.1758	13700	603.3	521.4	81.9	86.4	13.6
PARAKEET	556.5	24 x 0.1523	7 x 0.1015	0.914	0.304	19800	716.1	524.3	191.8	73.2	26.8
DOVE	556.5	26 x 0.1463	7 x 0.1138	0.927	0.341	22600	765.2	524.2	241.0	68.5	31.5
EAGLE	556.5	30 x 0.1362	7 x 0.1362	0.953	0.409	27800	870.7	525.4	345.3	60.4	39.6
PEACOCK	605	24 x 0.1588	7 x 0.1059	0.953	0.318	21600	778.8	570.1	208.7	73.2	26.8
SWIFT	636	36 x 0.1329	1 x 0.1329	0.930	0.1329	13800	642.8	596.0	46.8	92.7	7.3
KINGBIRD	636	18 x 0.1880	1 x 0.1880	0.940	0.1880	15700	689.9	596.3	93.6	86.4	13.6
ROOK	636	24 x 0.1628	7 x 0.1085	0.977	0.326	22600	818.2	599.1	219.1	73.2	26.8
GROSBEAK	636	26 x 0.1564	7 x 0.1216	0.990	0.365	25200	874.2	599.0	275.2	68.5	31.5
EGRET	636	30 x 0.1456	19 x 0.0874	1.019	0.437	31500	987.2	600.5	386.7	60.8	39.2
FLAMINGO	666.6	24 x 0.1667	7 x 0.1111	1.000	0.333	23700	857.9	628.2	229.7	73.2	26.8
STARLING	715.5	26 x 0.1659	7 x 0.1290	1.051	0.387	28400	983.7	674.0	309.7	68.5	31.5
REDWING	715.5	30 x 0.1544	19 x 0.0926	1.081	0.463	34600	1109.3	675.3	434.0	60.8	39.2
COOT	795	36 x 0.1486	1 x 0.1486	1.040	0.1486	16800	803.6	745.1	58.5	92.7	7.3
TERN	795	45 x 0.1329	7 x 0.0886	1.063	0.266	22100	895	749	146	83.7	16.3
CUCKOO	795	24 x 0.1820	7 x 0.1213	1.092	0.364	27900	1023	749	274.0	73.2	26.8
CONDOR	795	54 x 0.1213	7 x 0.1213	1.092	0.364	28200	1022	748	274.0	73.2	26.8
DRAKE	795	26 x 0.1749	7 x 0.1360	1.108	0.408	31500	1093	749	344	68.5	31.5
MALLARD	795	30 x 0.1628	19 x 0.0977	1.140	0.489	38400	1233.9	750.7	483.2	60.8	39.2
RUDDY	900	45 x 0.1414	7 x 0.0943	1.131	0.283	24400	1013	848	165	83.7	16.3
CANARY	900	54 x 0.1291	7 x 0.1291	1.162	0.387	31900	1158	848	310	73.2	26.8
CORNCRAKE	954	20 x 0.2184	7 x 0.0971	1.165	0.291	25600	1074	899	175	83.7	16.3
REDBIRD	954	24 x 0.1994	7 x 0.1329	1.196	0.399	33500	1228	899	329	73.2	26.8
TOWHEE	954	48 x 0.1410	7 x 0.1097	1.175	0.329	28500	1123	899	224	80.1	19.9
RAIL	954	45 x 0.1456	7 x 0.0971	1.165	0.291	25900	1075	899	176	83.7	16.3
CARDINAL	954	54 x 0.1329	7 x 0.1329	1.196	0.399	33800	1227.1	898.4	328.7	73.2	26.8
ORTOLAN	1033.5	45 x 0.1515	7 x 0.1010	1.212	0.303	27700	1163	973	190	83.7	16.3
CURLEW	1033.5	54 x 0.1383	7 x 0.1383	1.245	0.415	36600	1329	973	356	73.2	26.8
BLUEJAY	1113.0	45 x 0.1573	7 x 0.1049	1.259	0.315	29800	1254	1049	205	83.7	16.3
FINCH	1113.0	54 x 0.1436	19 x 0.0862	1.293	0.431	39100	1430	1054	376	73.7	26.3
BUNTING	1192.5	45 x 0.1628	7 x 0.1085	1.302	0.326	32000	1342	1123	219	83.7	16.3
GRACKLE	1192.5	54 x 0.1486	19 x 0.0892	1.338	0.446	41900	1531	1128	403	73.7	26.3
SKYLARK	1272.0	36 x 0.1880	1 x 0.1880	1.316	0.1880	26400	1286	1192	94	92.7	7.3
BITTERN	1272.0	45 x 0.1681	7 x 0.1121	1.345	0.336	34100	1432	1198	234	83.7	16.3
PHEASANT	1272.0	54 x 0.1535	19 x 0.0921	1.382	0.461	43600	1634	1205	429	73.7	26.3
DIPPER	1351.5	45 x 0.1733	7 x 0.1155	1.386	0.347	36200	1521	1273	248	83.7	16.3
MARTIN	1351.5	54 x 0.1582	19 x 0.0949	1.424	0.475	46300	1735	1279	456	73.7	26.3
BOBOLINK	1431.0	45 x 0.1783	7 x 0.1189	1.427	0.357	38300	1611	1348	263	83.7	16.3
PLOVER	1431.0	54 x 0.1628	19 x 0.0977	1.465	0.489	49100	1838	1355	483	73.7	26.3
LAPWING	1590.0	45 x 0.1880	7 x 0.1253	1.504	0.376	42200	1790	1498	292	83.8	16.3
FALCON	1590.0	54 x 0.1716	19 x 0.1030	1.545	0.515	54500	2042	1505	537	73.7	26.3
CHUKAR	1780.0	84 x 0.1456	19 x 0.0874	1.602	0.437	51000	2072	1685	387	81.3	18.7
MOCKINGBIRD	2034.5	72 x 0.1681	7 x 0.1122	1.681	0.337	46800	2163	1929	234	89.2	18.7
BLUEBIRD	2156.0	84 x 0.1602	19 x 0.0961	1.762	0.481	60300	2508	2040	468	81.3	18.7
KIWI	2167.0	72 x 0.1735	7 x 0.1157	1.735	0.347	49800	2301	2052	249	89.2	10.8
THRASHER	2312.0	76 x 0.1744	19 x 0.0814	1.802	0.407	56700	2523	2188	335	86.7	13.3
JOREA	2515.0	76 x 0.1819	19 x 0.0850	1.880	0.425	61700	2749	2383	366	86.7	13.3
High Strength ACSR											
GROUSE	80.0	8 x 0.1000	1 x 0.1670	0.367	0.1670	5200	148.8	74.9	73.9	50.3	49.7
PETREL	101.8	12 x 0.0921	7 x 0.0921	0.461	0.276	10400	253.8	95.9	157.9	37.8	62.2
MINORCA	110.8	12 x 0.0961	7 x 0.0961	0.481	0.288	11300	276.3	104.4	171.9	37.8	62.2
LEGHORN	134.6	12 x 0.1059	7 x 0.1059	0.530	0.318	13600	335.5	126.8	208.7	37.8	62.2
GUINEA	159.0	12 x 0.1151	7 x 0.1151	0.576	0.345	16000	396.3	149.7	246.6	37.8	62.2
DOTTEREL	176.9	12 x 0.1214	7 x 0.1214	0.607	0.364	17300	440.9	166.6	274.3	37.8	62.2
DORKING	190.8	12 x 0.1261	7 x 0.1261	0.631	0.378	18700	475.7	179.7	296.0	37.8	62.2
COCKHIN	211.3	12 x 0.1327	7 x 0.1327	0.664	0.398	20700	526.8	199.0	327.8	37.8	62.2
BRAHMA	203.2	16 x 0.1127	19 x 0.0977	0.714	0.489	28400	674.6	191.4	483.2	28.4	71.6

ACSR

Aluminum Conductor Steel Reinforced

Electrical Properties

CODE WORD	SIZE & STRANDING AWG or kcmil	SIZE & STRANDING Aluminum/ Steel	RESISTANCE DC (Ohms/1000 Ft.) @20°	RESISTANCE AC-60-HZ(Ohms/1000 Ft.) @25° C	RESISTANCE AC-60-HZ(Ohms/1000 Ft.) @50° C	RESISTANCE AC-60-HZ(Ohms/1000 Ft.) @75° C	60 HZ REACTANCE 1 FOOT EQUIVALENT SPACING Capacitive (Megohms-1000 Ft.)	60 HZ REACTANCE Inductive (Ohms/1000 Ft.) @25° C	60 HZ REACTANCE Inductive (Ohms/1000 Ft.) @50° C	60 HZ REACTANCE Inductive (Ohms/1000 Ft.) @75° C
TURKEY	6	6/1	0.6419	0.6553	0.750	0.8159	0.7513	0.1201	0.1390	0.1439
SWAN	4	6/1	0.4032	0.4119	0.4794	0.5218	0.7149	0.1152	0.1314	0.1369
SWANATE	4	7/1	0.3989	0.4072	0.4633	0.5165	0.7102	0.11533	0.1239	0.1303
SPARROW	2	6/1	0.2534	0.2591	0.3080	0.3360	0.6785	0.1100	0.1235	0.1277
SPARATE	2	7/1	0.2506	0.2563	0.2966	0.3297	0.6737	0.1081	0.1176	0.1206
ROBIN	1	6/1	0.2011	0.2059	0.2474	0.2703	0.6600	0.1068	0.1191	0.1224
RAVEN	1/0	6/1	0.1593	0.1633	0.1972	0.2161	0.6421	0.1040	0.1138	0.1163
QUAIL	2/0	6/1	0.1265	0.1301	0.1616	0.1760	0.6241	0.1017	0.1117	0.1135
PIGEON	3/0	6/1	0.1003	0.1034	0.1208	0.1445	0.6056	0.0992	0.1083	0.1095
PENGUIN	4/0	6/1	0.0795	0.0822	0.1066	0.1157	0.5966	0.0964	.01047	0.1053
								Inductive (Ohms/1000 Ft.)	GMR (Ft.)	
WAXWING	266.8	18/1	0.0644	0.0657	0.0723	0.0788	0.576	0.0934	0.0197	
PARTRIDGE	266.8	26/7	0.0637	0.0652	0.0714	0.0778	0.565	0.0881	0.0217	
MERLIN	336.4	18/1	0.0510	0.0523	0.0574	0.0625	0.560	0.0877	0.0221	
LINNET	336.4	26/7	0.0506	0.0517	0.0568	0.0619	0.549	0.0854	0.0244	
ORIOLE	336.4	30/7	0.0502	0.0513	0.0563	0.0614	0.544	0.0843	0.0255	
CHICKADEE	397.5	18/1	0.0432	0.0443	0.0487	0.0528	0.544	0.0856	0.0240	
IBIS	397.5	26/7	0.0428	0.0438	0.0481	0.0525	0.539	0.0835	0.0265	
LARK	397.5	30/7	0.0425	0.0434	0.0477	0.0519	0.533	0.0824	0.0277	
PELICAN	477.0	18/1.	0.0360	0.0369	0.0405	0.0441	0.528	0.0835	0.0263	
FLICKER	477.0	24/7	0.0358	0.0367	0.0403	0.0439	0.524	0.0818	0.0283	
HAWK	477.0	26/7	0.0357	0.0366	0.0402	0.0438	0.522	0.0814	0.0290	
HEN	477.0	30/7	0.0354	0.0362	0.0389	0.0434	0.517	0.0803	0.0304	
OSPREY	556.5	18/1	0.0309	0.0318	0.0348	0.0379	0.518	0.0818	0.0284	
PARAKEET	556.5	24/7	0.0307	0.0314	0.0347	0.0377	0.512	0.0801	0.0306	
DOVE	556.5	26/7	0.0305	0.0314	0.0345	0.0375	0.510	0.0795	0.0313	
EAGLE	556.5	30/7	0.0300	0.0311	0.0341	0.0371	0.505	0.0786	0.0328	
PEACOCK	605.0	24/7	0.0282	0.0290	0.0378	0.0347	0.505	0.0792	0.0319	
SWIFT	636.0	36/1	0.0267	0.0281	0.0307	0.0334	0.509	0.0806	0.0300	
KINGBIRD	636.0	18/1	0.0269	0.0278	0.0306	0.0332	0.507	0.0805	0.0301	
ROOK	636.0	24/7	0.0268	0.0277	0.0300	0.0330	0.502	0.0786	0.0327	
GROSBEAK	636.0	26/7	0.0267	0.0275	0.0301	0.0328	0.500	0.0780	0.0335	
EGRET	636.0	30/19	0.0266	0.0273	0.0299	0.0326	0.495	0.0769	0.0351	
FLAMINGO	666.6	24/7	0.0256	0.0263	0.0290	0.0314	0.498	0.0780	0.0335	
STARLING	715.5	26/7	0.0238	0.0244	0.0269	0.0292	0.490	0.0767	0.0355	
REDWING	715.5	30/19	0.0236	0.0242	0.0267	0.0290	0.486	0.0756	0.0372	
COOT	795.0	36/1	0.0217	0.0225	0.0247	0.0268	0.492	0.0780	0.0335	
TERN	795.0	45/7	0.0216	0.0225	0.0246	0.0267	0.488	0.0764	0.0352	
CUCKOO	795.0	24/7	0.0215	0.0223	0.0243	0.0266	0.484	0.0763	0.0361	
CONDOR	795.0	54/7	0.0215	0.0222	0.0244	0.0265	0.484	0.0759	0.0368	
DRAKE	795.0	26/7	0.0214	0.0222	0.0242	0.0263	0.482	0.0756	0.0375	
MALLARD	795.0	30/19	0.0213	0.0220	0.0241	0.0261	0.477	0.0744	0.0392	
RUDDY	900.0	45/7	0.0191	0.0200	0.0218	0.0237	0.479	0.0755	0.0374	
CANARY	900.0	54/7	0.0190	0.0197	0.0216	0.0235	0.474	0.0744	0.0392	
CORNCRAKE	954.0	20/7	0.0180	0.0188	0.0206	0.0224	0.474	0.0751	0.0378	
REDBIRD	954.0	24/7	0.0179	0.0186	0.0204	0.0221	0.470	0.0742	0.0396	
TOWHEE	954.0	48/7	0.0180	0.0188	0.0205	0.0223	0.473	0.0745	0.0391	
RAIL	954.0	45/7	0.0180	0.0188	0.0206	0.0223	0.474	0.0748	0.0385	
CARDINAL	954.0	54/7	0.0179	0.0186	0.0205	0.0222	0.470	0.0757	0.0404	
ORTOLAN	1033.5	45/7	0.0167	0.0175	0.0191	0.0208	0.468	0.0739	0.0401	
CURLEW	1033.5	54/7	0.0165	0.0172	0.0189	0.0201	0.464	0.0729	0.0420	
BLUEJAY	1113.0	45/7	0.0155	0.0163	0.0178	0.0193	0.462	0.0731	0.0416	
FINCH	1113.0	54/19	0.0154	0.0161	0.0176	0.0191	0.458	0.0702	0.0436	
BUNTING	1192.5	45/7	0.0144	0.0152	0.0167	0.0181	0.456	0.0723	0.0431	
GRACKLE	1192.5	54/19	0.0144	0.0151	0.0165	0.0179	0.452	0.0710	0.0451	
SKYLARK	1272.0	36/1	0.0135	0.0145	0.0159	0.0173	0.455	0.072	0.0427	
BITTERN	1272.0	45/7	0.0135	0.0144	0.0157	0.0170	0.451	0.072	0.0445	
PHEASANT	1272.0	54/19	0.0135	0.0142	0.0155	0.0169	0.447	0.070	0.0466	
DIPPER	1351.5	45/7	0.0127	0.0136	0.0148	0.0161	0.447	0.071	0.0459	
MARTIN	1351.5	54/19	0.0127	0.0134	0.0147	0.0159	0.442	0.070	0.0480	
BOBOLINK	1431.0	45/7	0.0120	0.0129	0.0141	0.0152	0.442	0.070	0.0472	
PLOVER	1431.0	54/19	0.0120	0.0127	0.0134	0.0151	0.438	0.069	0.0495	
LAPWING	1590.0	45/7	0.0108	0.0117	0.0127	0.0138	0.434	0.069	0.0498	
FALCON	1590.0	54/19	0.0108	0.0116	0.0126	0.0137	0.430	0.068	0.0521	
CHUKAR	1780.0	84/19	0.0097	0.0106	0.0115	0.0125	0.424	0.067	0.0534	
MOCKINGBIRD	2034.5	72/7	0.0085	0.0096	0.0104	0.0112	0.416	0.066	0.0553	
BLUEBIRD	2156.0	84/19	0.0080	0.0090	0.0098	0.0105	0.409	0.065	0.0588	
KIWI	2167.0	72/7	0.0080	0.0092	0.0099	0.0106	0.411	0.068	0.0570	
THRASHER	2312.0	76/19	0.0075	0.0086	0.0092	0.0100	0.405	0.065	0.0600	
JOREA	2515.0	76/19	0.0069	0.0081	0.0087	0.0093	0.399	0.064	0.0621	
							60 HZ REACTANCE 1 FOOT EQUIVALENT SPACING			
HIGH STRENGTH ACSR							Capacitive (Megohms-1000 Ft.)	Inductive (Ohms/1000 Ft.) @25° C	Inductive (Ohms/1000 Ft.) @50° C	Inductive (Ohms/1000 Ft.) @75° C
GROUSE	80.0	8/1	0.2065	0.2110	0.2362	0.2612	0.6547	0.1047	0.1129	0.1150
PETREL	101.8	12/7	0.1583	0.1625	0.2072	0.2394	0.6193	0.1019	0.1161	0.1282
MINORCA	110.8	12/7	0.1454	0.1491	0.1932	0.2233	0.6125	0.1017	0.1176	0.1269
LEGHORN	134.6	12/7	0.1198	0.1233	0.1638	0.1894	0.5972	0.0998	0.1148	0.1227
GUINEA	159.0	12/7	0.1014	0.1045	0.1426	0.1653	0.5845	0.0979	0.1117	0.1189
DOTTEREL	176.9	12/7	0.0911	0.0945	0.1301	0.1513	0.5760	0.0970	0.1102	0.1169
DORKING	190.8	12/7	0.0845	0.0875	0.1229	0.1424	0.5697	0.0956	0.1093	0.1150
COCHIN	211.3	12/7	0.0763	0.0792	0.1125	0.1311	0.5618	0.0945	0.1074	0.1129
BRAHMA	203.2	16/19	0.0764	0.0790	0.1089	0.1348	0.5507	0.0934	0.1047	0.1121

Notes:
1. DC reesistance is based on 16.946 ohn-cmil/ft. 61.2% IACS for 1350 wires and 129.64 ohm-cmil/ft. 8% IACS for the steel core at 20° C with stranding increment as per ASTM B232.

APPENDIX F

The following assessment is based on the MnDNR response letter, a review of the Natural Heritage Database specific to Dakota County that is licensed to Xcel Energy by the MnDNR, and other state and federal rare species and natural community information.

The MnDNR NHIS database was queried to obtain the locations of rare and unique natural resources within the Project Area. Queries to the NHIS database often display species that either do not have a legal status or are of special concern (referred to as "SPC" in the table below). Species or communities that do not have a status, or are classified as special concern, have no legal protection in Minnesota. Only potential impacts on non-aquatic species with legal protection (threatened and endangered) are discussed below.

Although numerous known occurrences of rare species or special communities have been identified within one mile of the Project Area, only two were identified via the MnDNR NHIS database within the immediate Project Area; the peregrine falcon (*Falco peregrinus*) and the paddlefish (*Polyodon spathula*). With the exception of these two species, all rare or unique resources are located outside of the Project Area. In addition, in its March 8, 2011 letter, the MnDNR stated that the Minnesota County Biological Survey completed in 1994 indentified Bulrush Marsh native plant communities adjacent to the proposed transmission lines. The MnDNR has assigned a state ranking of 3 to the Bulrush Marsh plant community, meaning it is vulnerable to extirpation in Minnesota.

Because the Project will be limited to upland areas, no impacts on the state-listed threatened paddlefish are anticipated. Further, the MnDNR stated that provided the transmission foundations are located in upland areas as proposed, the Project is not expected to directly impact the Bulrush Marsh native plant communities. However, as recommended by the MnDNR, Xcel Energy will attempt to mitigate for surface runoff or the spread of invasive species into this community during construction. Mitigation measures may include use of best management practices such as installation of erosion control devices to prevent runoff in to the waterbody and use of clean equipment to prevent the transfer of noxious weeds to the construction site.

Xcel Energy is currently determining specific engineering Project details such as structure placement. While it anticipates the Project will be confined to upland areas,

if Project details change such that a structure(s) will require placement in shoreline areas or in waterbodies, Xcel Energy will contact the MnDNR to develop mitigation measures, if necessary, to avoid adversely impacting any state-listed threatened or endangered aquatic species (e.g., paddlefish).

Regarding the state-listed threatened peregrine falcon, the species is known to have regularly nested on a smokestack at the existing Black Dog Plant since 1993. The MnDNR stated that it is unlikely that the transmission line construction as proposed would affect this species.

It is anticipated that the smokestack with the nest box will be taken down sometime in 2016 or later. Prior to taking down the smokestack, the nest box will be removed while the nest is inactive. Xcel Energy will work with the MnDNR to relocate the nest box on an appropriate structure after construction is complete, similar to what has occurred on past repowering projects, i.e. High Bridge, and Riverside plants.

Two additional species were identified in the MnDNR's letter: the federally listed as threatened and state-listed as special concern gray wolf, and the federally listed as threatened Canada lynx. Both species are not currently tracked in the MnDNR NHIS database and, therefore, historical locations are unknown. However, based on the two species' habitat and range (i.e., northern Minnesota) (MnDNR, 2011b; MnDNR, 2011c), it is unlikely they would be affected by the Project.

Another species warranting recognition is the bald eagle (*Haliaeetus leucocephalus*), which is granted SPC status in the State of Minnesota and is afforded legal protection under the Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act. A bald eagle nest is known to occur approximately 1,000 feet to the north of the Project Area. Efforts will be made to determine if the bald eagle nest is occupied prior to initiation of construction activities.

Rare and Unique Resources Identified by MnDNR NHIS Review within One Mile of the Project Area

Common Name	Scientific Name	Most Recent Observation	MN Status [a]	State Rank [a]
Zoological [a]				
Bald Eagle	*Haliaeetus leucocephalus*	2005	SPC	S3
Black Buffalo	*Ictiobus niger*	2006	SPC	S3
Black Sandshell	*Ligumia recta*	1989 and 2006	SPC	S3
Butterfly	*Ellipsaria lineolata*	2005	THR	S2
Ebonyshell	*Fusconaia ebena*	2001	END	S1
Elephant-ear	*Elliptio crassidens*	1977	END	S1
Fluted-shell	*Lasmigona costata*	2006	SPC	S3
Hickorynut	*Obovaria olivaria*	2006	SPC	S3
Monkeyface	*Quadrula metanevra*	2006	THR	S2
Mucket	*Actinonaias ligamentina*	1989 and 2006	THR	S2
Paddlefish	*Polyodon spathula*	2004	THR	S2
Peregrine falcon	*Falco peregrinus*	2010	THR	S2
Pistolgrip	*Tritogonia verrucosa*	1989	THR	S2
Pugnose shiner	*Notropis anogenus*	1926	SPC	S3
Regal Fritillary	*Speyeria idalia*	1968	SPC	S3
Rock Pocketbook	*Arcidens confragosus*	2006	END	S1
Round Pigtoe	*Pleurobema coccineum*	2006	THR	S2
Spike	*Elliptio dilatata*	1989 and 2006	SPC	S3
Wartyback	*Quadrula nodulata*	2007	END	S1
Washboard	*Megalonaias nervosa*	2006	THR	S2
Winged mapleleaf [b]	*Quadrula fragosa*	1989	END	S1
Yellow sandshell	*Lampsilis teres*	1989	END	S1
Botanical				
Small white lady's-slipper	*Cypripedium candidum*	1993	SPC	S3
Snow trillium	*Trillium nivale*	2008	SPC	S3
Sterile sedge	*Carex sterilis*	1994	THR	S2
Tuberous Indian-plantain	*Arnoglossum plantagineum*	1993	THR	S2

Common Name	Scientific Name	Most Recent Observation	MN Status [a]	State Rank [a]
Valerian	*Valeriana edulis var. ciliata*	1993	THR	S2
Ecological				
Calcareous Fen (Southeastern Type)	--	1993 and 1994	N/A	S1
Native Plant Community, Undetermined Class	--	1994	N/A	SNR
Southern Wet Ash Swamp	--	1995	N/A	S2

[a] At the state level, "THR" refers to species listed as threatened, "END" refers to species listed as endangered, "SPC" refers to species of special concern. In addition, Minnesota also assigns a rank to listed species. This rank reflects the known extent and condition of that species. Ranks range from S1 (in greatest need of conservation action in the state) to S5 (secure under present conditions), and SNR (rank not yet assessed).

[b] This species is also covered under the federal Endangered Species Act and is currently listed as Endangered.

MnDNR letter reference:

Minnesota Department of Natural Resources. 2011a. Letter dated March 8, from L. Joyal (Natural Heritage Review Coordinator) to T. Janssen (Merjent, Inc.).

References for gray wolf and Canada lynx statements:

Minnesota Department of Natural Resources. 2011b. Gray Wolf/Timber Wolf. Available online at http://www.dnr.state.mn.us/mammals/graywolf.html. Accessed March 2011.

Minnesota Department of Natural Resources. 2011c. Canada Lynx. Available online at http://www.dnr.state.mn.us/mammals/canadalynx.html. Accessed March 2011.

Minnesota Historical Society

STATE HISTORIC PRESERVATION OFFICE

February 15, 2011

Ms. Peggy Boden
Merjent
615 First Ave NE, Suite 425
Minneapolis, MN 55413

RE: Xcel Energy Black Dog Repower Project
T27 R24 S23
Burnsville, Dakota County
SHPO Number: 2011-1100

Dear Ms. Boden:

Thank you for the opportunity to review and comment on the above project. It has been reviewed pursuant to the responsibilities given the Minnesota Historical Society by the Minnesota Historic Sites Act and the Minnesota Field Archaeology Act.

Based on our review of the project information, we conclude that there are no properties listed on the National or State Registers of Historic Places, and no known or suspected archaeological properties in the area that will be affected by this project.

Please note that this comment letter does not address the requirements of Section 106 of the National Historic Preservation Act of 1966 and 36CFR800, Procedures of the Advisory Council on Historic Preservation for the protection of historic properties. If this project is considered for federal assistance, or requires a federal permit or license, it should be submitted to our office with reference to the assisting federal agency.

Please contact our Compliance Section at (651) 259-3455 if you have any questions regarding our review of this project.

Sincerely,

Britta L. Bloomberg
Deputy State Historic Preservation Officer

Minnesota Historical Society, 345 Kellogg Boulevard West, Saint Paul, Minnesota 55102
651-259-3000 • 888-727-8386 • www.mnhs.org

Appendix H

Table 1
Project Generating Capability

Summer Conditions (89°F, 47% Relative Humidity)			
Capability		Net Heat Rate (Btu/kWh) (HHV)	Efficiency (%) (HHV)
% of Base	MW		
TRADE SECRET DATA BEGINS HERE			
TRADE SECRET DATA ENDS HERE			
Winter Conditions (-5°F, 60% Relative Humidity)			
Capability		Net Heat Rate (Btu/kWh) (HHV)	Efficiency (%) (HHV)
% of Base	MW		
TRADE SECRET DATA BEGINS HERE			
TRADE SECRET DATA ENDS HERE			
Reference Temperature Conditions (59°F, 60% Relative Humidity)			
Capability		Net Heat Rate (Btu/kWh) (HHV)	Efficiency (%) (HHV)
% of Base	MW		
TRADE SECRET DATA BEGINS HERE			
TRADE SECRET DATA ENDS HERE			

Table 2
Project Fuel Requirements

Rule Reference	Description	Project Data
		TRADE SECRET DATA BEGINS HERE
7849.0320, C(1)	Fuel (Natural Gas) Source	
7849.0320, C(2)	Fuel Requirement •summer, peak •winter, peak •reference temperature, base load •Annual consumption	
7849.0320, C(3)	Heat Input (HHV) •summer, peak •winter, peak •reference temperature, base load	
7849.0320, C(4)	Fuel (natural gas) Heat Value	
7849.0320, C(5)	Fuel Content: Sulfur Ash Moisture Content	
		TRADE SECRETE DATA ENDS HERE

Table 3
Project Cost Summary

Item	Black Dog Repowering Project Costs
	TRADE SECRET DATA BEGINS HERE
Project Base Capacity Cost	
Base Summer Capacity Costs in $/kW	
Base Total Cost in $/kWh	
Annual Revenue Requirement in $/kWh	
Fuel Costs in $/kWh	
Variable O&M Costs in $/kWh	
	TRADE SECRET DATA ENDS HERE