Appendices to Application for a Certificate of Need for the Monticello Nuclear Generating Plant

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Order Granting Certificate of Need for Interim Independent Spent Fuel Storage Installation ..... Attachment 3

Appendix A: CON 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 1.1 Chapter 5
1	Demand forecast for type of energy supplied by proposed facility is accurate	Chapter 1.5 Chapter 3.8 Chapter 5.1 & 5.2 Chapter 7.1 Appendix B.5 & B.10
2	Effects of applicant's conservation program and state and federal conservation programs	Chapter 1.1, 1.2, 1.4 & 1.5 Chapter 5.2 Chapter 7.1 Appendix C.2
3	Effects of applicant's promotional practices on energy demand	Chapter 1.1, 1.2 & 1.7 Chapter 5.2
4	Ability of current facilities and facilities not requiring certificate of need to meet future demand	Chapter 1.2 & 1.5 Chapter 5
5	Effect of proposed facility in making efficient use of resources	Chapter 1 Chapter 3.4 Chapter 5.2 Chapter 6.2 Chapter 7.1
7849.0120B	A more reasonable and prudent alternative has not been demonstrated	Chapter 1.5 Chapter 6 Appendix D
1	Appropriate size, type and timing compared to reasonable alternatives	Chapter 1.5 Chapter 3 – Tbl. 3-1 Chapter 6

Authority	Required Information	Location of Required Content
		Appendix D
2	Cost of facility and of its energy compared to reasonable alternatives	Chapter 1.5 Chapter 6 Appendix D
3	Effects on natural and socioeconomic environment vs. reasonable alternatives	Chapter 1.4 & 1.5 Chapter 3 Chapter 4.1 & 4.5 Chapter 6 Chapter 7.2 & 7.7 Chapter 8.1 Appendix D
4	Expected reliability of facility compared to reasonable alternatives	Chapter 1.5 Chapter 5 Chapter 6 Chapter 7.2 Appendix D
7849.0120C	Project benefit society by protecting the natural and socioeconomic environment, including human health, considering:	Chapter 1.4 &1.5 Chapter 6.4 Chapter 7.1 & 7.5 Chapter 8.1
1	Relationship of facility to overall state energy needs	Chapter 1.5 Chapter 2.2 Chapter 6 Chapter 7.6-.7
2	Effects of facility on natural and socioeconomic environment compared to not building facility	Chapter 1.4 & 1.5 Chapter 6.2 Chapter 7.6-.7 Chapter 8.1
3	Effects of facility inducing future development	Chapter 1.5 Chapter 7.1

Authority	Required Information	Location of Required Content
		Chapter 8.1
4	Socially beneficial uses of the output of the facility, including to protect or enhance environmental quality	Chapter 1.4 & 1.5 Chapter 7
7849.0120D	Project will comply with relevant policies and regulations of other state and federal agencies and local governments	Chapter 1.4 & 1.5 Chapter 2.4 Chapter 5 Chapter 6.4 Chapter 8
7849.0200	Application procedures and timing	Chapter 1.1 & 1.2 Chapter 2.4
7849.0210	Filing fee to accompany application	Chapter 2.3
7849.0220	Contents of application	Table of Contents Appendix A
7849.0230	Draft environmental report	Chapter 4
7849.0240	Need Summary and Additional Considerations	Chapter 1.2
7849.0240, Subp. 1	Need summary contains major factors that justify need for facility	Chapter 1.2 Chapter 2.4.2
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
7849.0240, Subp. 2B	Promotional activities that may have given rise to demand	Chapter 1.2, 1.4 & 1.5 Chapter 5
7849.0240 Subp. 2C	Effects of the facility in inducing future development	Chapter 7.1 Chapter 8.1
7849.0250	Description of proposed LEGF and alternatives	Appendix D
A	Description of the facility, including:	Chapter 3

Authority	Required Information	Location of Required Content
1	Nominal generating capability and economies of scale on the facility size and timing	Chapter 3 - Tbl. 3-1
2	Anticipated operating cycle including expected annual capacity factor	Chapter 2.2 Chapter 3.3; Tbl. 3-1 Chapter 4.2
3	Type of fuel used, including reason for choice of fuel, availability of fuel and alternative fuels, if any	Chapter 1.5 Chapter 2.4.2 Chapter 3.3; Tbl. 3-1 Chapter 6 Appendix D
4	Anticipated heat rate of the facility	Chapter 3.6 & 3.7 Chapter 3 - Tbl. 3-1 Chapter 6
5	Anticipated areas where the proposed facility could be located	Chapter 3.8; Tbl. 3-1
B	Discuss alternatives available	Chapter 1.5 Chapter 3 - Tbl. 3-1 Chapter 6 Appendix D
1	Purchased power	Chapter 3 - Tbl. 3-1 Chapter 5.2.4 Chapter 6.1 Chapter 7.1
2	Increased efficiency of existing facilities, including transmission lines	Chapter 3 - Tbl. 3-1 Chapter 6 Appendix D
3	New transmission lines	Chapter 3 - Tbl. 3-1 Chapter 4.2 Chapter 6

Authority	Required Information	Location of Required Content
4	New generating facilities of a different size or using a different energy source as fuel	Chapter 3 - Tbl. 3-1 Chapter 6 Chapter 7.1
5	Any reasonable combinations of the alternatives listed in items 1-4	Chapter 3 - Tbl. 3-1 Chapter 6 Chapter 7.1 Appendix D
C	For the facility and for each alternative in B that could provide electric power at the asserted level of need, discuss:	
1	Capacity cost in current $/kW	Chapter 1.4 Chapter 3.11 Chapter 3 - Tbl. 3-1 Chapter 5.2.2
2	Service life	Chapter 3.11; Tbl. 3-1
3	Estimated average annual availability	Chapter 3.11; Tbl. 3-1
4	Fuel costs in current $/kWh	Chapter 3.11; Tbl. 3-1 Chapter 5
5	Variable operating and maintenance costs in current $/kWh	Chapter 3.11; Tbl. 3-1
6	Total cost in current $/kWh	Chapter 3.11; Tbl. 3-1 Chapter 5
7	Estimated rate impact, system wide and in Minnesota, assuming a test year beginning with the proposed in-service date	Chapter 3.11; Tbl. 3-1 Appendix B
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	Chapter 3.11; Tbl. 3-1 Chapter 7.1
9	Major assumptions in providing the information in items 1-8, including projected	Chapter 3.11; Tbl. 3-1

Authority	Required Information	Location of Required Content
	escalation rates for fuel costs, O&M costs, and capacity factors	
D	Map showing the applicant's system	Chapter 3.1 & 3.2
E	Such other relevant information about the proposed facility and each alternative as may be relevant to need determination	Chapter .3 & Tbl. 3-1 Chapter 6.1.8 Appendix D
7849.0270-0290	System load, annual consumption forecast, capacity and conservation program information	Chapter 1.2 – 1.5 Chapter 5.1 Chapter 6 Appendix B.11 Appendix C
7849.0270	Peak Demand and Annual Consumption Forecast	Chapter 1.5 Chapter 5.2 Appendix B.11
7849.0270 subpt. 1	Pertinent data concerning peak demand and annual electrical consumption	Chapter 1.5 Chapter 5.2 Appendix B.10
7849.0270 subpt. 2	Provide the following data for each forecast year:	
A	Annual consumption by consumers within the MN service area	Chapter 1.5 Chapter 5.2 Appendix B.11
B	Estimates of number of consumers and their annual consumption for:	
(1)	Farm, excluding irrigation and drainage pumping	Appendix B.11
(2)	Irrigation and drainage pumping	Appendix B.11
(3)	Nonfarm residential	Appendix B.11
(4)	Commercial	Appendix B.11

Authority	Required Information	Location of Required Content
(5)	Mining	Appendix B.11
(6)	Industrial	Appendix B.11
(7)	Street and highway lighting	Appendix B.11
(8)	Electrified transportation	Appendix C.6
(9)	Other	Appendix B.11
(10)	Sum of sub items (1)-(9)	Appendix B.11
C	Estimated power demand at annual peak demand, broken down as in B.	Appendix B.12
D	System peak demand by month	Appendix B.11
E	Estimated annual revenue requirement per kW-hr (in current dollars)	Chapter 6
F	Estimated average system weekday load factor by month	Appendix B.11
subpt. 3	Detail of the forecast methodology employed in subpt. 2, including:	Appendix B
A	Overall methodological framework used	Chapter 6 Appendix B.1
B	Specific analytical techniques used, their purpose and where used	Appendix B.2
C	Manner in which the specific techniques are related	Appendix B.2 & B.3
D	Where statistical techniques have been used:	
(1)	Purpose of the technique	Appendix B.2
(2)	Typical computations, specifying variables and data	Appendix B.2
(3)	Results of appropriate statistical tests	Appendix B.2
E	Forecast confidence levels or ranges for peak demand and consumption	Appendix B.2

Authority	Required Information	Location of Required Content
F	A brief analysis of the methodology used, including:	Chapter 6 Appendix B.2
(1)	Strengths and weaknesses	Appendix B.4
(2)	Suitability to the system	Appendix B.4
(3)	Cost considerations	Appendix B.4
(4)	Data requirements	Appendix B.4
(5)	Past accuracy	Appendix B.4
(6)	Other factors considered significant	Appendix B.4
G	Explanation of discrepancies between current and previous forecasts	Appendix B.9 & B.10
subpt. 4	Discussion of the database used in current forecasting, including:	Appendix B.7
A	Complete list and description of all datasets used in the forecast	Appendix B.5
B	Clear identification of adjustments made to raw data including:	Appendix B.7
(1)	Nature of adjustment	Appendix B.7
(2)	Reason for adjustment	Appendix B.7
(3)	Magnitude of adjustment	Appendix B.7
subpt. 5	Discussion of each assumption made in forecast preparation, including:	Appendix B.5 & B.7
A	Availability of alternate sources of energy	Chapter 5 Appendix D
B	Expected conversion from other fuels to electricity or vice versa	Chapter 5 Appendix D
C	Future prices and their projected impact upon system demand	Chapter 5.2 Appendix D

Authority	Required Information	Location of Required Content
D	Subpt. 2 data that is not available historically or internally generated	Appendix D
E	Impact of energy conservation programs upon electrical demand	Chapter 5.2.2 Appendix D
F	Any other factor considered in preparing the forecast	Chapter 5.2 Chapter 6 Appendix D
subpt. 6	Applicant shall provide:	
A	Description of coordination of load forecasts with other systems	Chapter 5 Appendix B
B	Description of the manner in which forecasts are coordinated	Chapter 5 Appendix B
7849.0280	Description of ability of existing system to meet forecast demand	Chapter 1.5 Chapter 2.4.4 Chapter 5
A	Discussion of power planning programs applied	Chapter 5.2 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
(1)	Seasonal system demand	Appendix B
(2)	Annual system demand	Appendix B
(3)	Total seasonal firm purchases	Appendix B
(4)	Total seasonal firm sales	Appendix B
(5)	Seasonal adjusted net demand	Appendix B

Authority	Required Information	Location of Required Content
(6)	Annual adjusted net demand	Appendix B
(7)	Net generating capacity	Appendix B
(8)	Total participation purchases	Appendix B
(9)	Total participation sales	Appendix B
(10)	Adjusted net capability	Appendix B
(11)	Net reserve capacity obligation	Appendix B
(12)	Total firm capacity obligation	Appendix B
(13)	Surplus or deficit capacity	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.13
H	Graph of monthly adjusted net demand and capability; plot of difference between capability and maintenance outages	Appendix B.13
I	Appropriateness and method of determining system reserve margins	Appendix B.13
7849.0290	Application must include the following regarding conservation programs:	
A	Party (ies) responsible for energy conservation and efficiency programs	Appendix C.1
B	List of energy conservation and efficiency goals and objectives	Appendix C.2
C	Description of programs considered, implemented and rejected	Appendix C.3

Authority	Required Information	Location of Required Content
D	Description of major accomplishments in conservation and efficiency	Appendix C.4
E	Description of future plans with respect to conservation and efficiency	Appendix C.5
F	Quantification of the manner by which these programs impact the forecast	Appendix C.6
7849.0300	Consequences of indefinite delay or 1,2, or 3 year postponement	Chapter 5.3
7849.0310	Environmental information requested	Chapter 4
7849.0320	Provide data for each alternative that would involve LEGF construction	Chapter 4 - Tbl. 4-5
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	Chapter 3.1 Chapter 4.1 & 4.2 Chapter 4 - Tbl. 4-5 Chapter 7.3 Appendix D
B	Estimated vehicular, rail, barge traffic generated by construction and operation of the facility	Chapter 4.2 Chapter 4 - Tbl. 4-5 Appendix D.3
C	For fossil-fueled facilities:	
1	Expected regional fuel sources for the facility	Chapter 3 Chapter 4 - Tbl. 4-5 Appendix D.3 & D.4
2	Typical fuel requirement during operation at rated capacity and annual fuel requirement at expected capacity factor	Chapter 3 Chapter 4 - Tbl. 4-5 Chapter 6.2
3	Expected rate of heat input in Btu per hour at rated capacity	Chapter 3 Appendix D.2 & D.3 Chapter 4 - Tbl. 4-5

Authority	Required Information	Location of Required Content
4	Typical range of heat value of the fuel (in Btu/lb, Btu/gallon or Btu/1000Cf) and typical average heat value	Chapter 3 Chapter 4 - Tbl. 4-5 Appendix D.3
5	Typical ranges of sulfur, ash and moisture content of the fuel	Chapter 3 Chapter 4 - Tbl. 4-5 Appendix D.3
D	For Fossil fueled facilities:	Not Applicable
1	Estimated range of trace element emissions and maximum emissions of SO2, NOx, and PM in lbs/hour during operation at rated capacity	Not Applicable
2	Estimated range of maximum contributions to 24-hour average ground level concentrations at specified distances from stack of SO2, NOx and PM in micrograms/cubic meter at rated capacity and assuming generalized worst-case meteorological conditions	Not Applicable
E	Water use by the facility for alternate cooling systems, including:	Chapter 3.11 Chapter 4.2 Chapter 4 - Tbl. 4-5 Appendix D.2 - D.4
1	Estimated maximum use, including the groundwater pumping rate in gallons/minute and surface water appropriation in cubic feet/second	Chapter 3.11 Chapter 4.2 Chapter 4 - Tbl. 4-5 Appendix D.2 - D.4
2	Estimated ground water appropriation in million gallons/year	Chapter 3.11 Chapter 4.2 Chapter 4 - Tbl. 4-5 Appendix D.2 - D.4
3	Annual consumption in acre-feet	Chapter 3.11

Authority	Required Information	Location of Required Content
		Chapter 4.2 Chapter 4 - Tbl. 4-5 Appendix D.2 - D.4
F	Potential sources and types of discharges to water attributable to operation of the facility	Chapter 4.2 Chapter 4 - Tbl. 4-5 Appendix D.2 - D.4
G	Radioactive releases, including:	
1	For nuclear facilities, typical levels	Chapter 4.2 Chapter 4 - Tbl. 4-5
2	For fossil-fueled facilities, the estimated range of radioactivity released by the facility in curies per year	Chapter 4.2 Chapter 4 - Tbl. 4-5
H	Potential types and quantities of solid wastes in tons per year at expected capacity factor	Chapter 4.2 Chapter 4 - Tbl. 4-5
I	Potential sources and types of audible noise attributable to operation	Chapter 4.2 Chapter 4 - Tbl. 4-5
J	Estimated work force required for construction and operation	Chapter 4.2 Chapter 4 - Tbl. 4-5
K	Minimum number and size of transmission facilities required to provide reliable outlet	Chapter 4.2 Chapter 4 - Tbl. 4-5
7849.0340	Alternative of no facility	Chapter 6 Appendix D
A	Expected operation of existing and committed facilities	Chapter 4.1 Chapter 6.1 Chapter 8.1
B	Description of the changes in resource requirements and wastes produced	Chapter 4.1 Chapter 8.1
C	Description of possible methods of reducing environmental impact	Chapter 4.1 Chapter 8.1

Authority	Required Information	Location of Required Content
Minn. Stat. §216B.243	Certificate of Need Criteria	Chapter 1.5 Chapter 2.4.1 & 2.4.3 Chapter 8
Subd. 2	Certificate required for this facility	Chapter 1.5 Chapter 2.4 Chapter 6 Chapter 8.2
Subd. 3	Showing required for construction. In assessing need, the Commission shall evaluate:	
1	Accuracy of the long-range energy demand forecast on which need is based	Chapter 5 Appendix B.10
2	Effect of existing or possible conservation on long-term demand	Chapter 1.4 & 1.5 Chapter 2.4.4 Chapter 5.2 Appendix D.3
3	Relationship of proposed facility to overall state energy needs, as described in most recent state energy policy report	Chapter 8.1 Appendix B.10
4	Promotional activities that may have given rise to the demand for this facility	Chapter 1.2; 1.4 & 1.7 Chapter 5.2.2 Chapter 8.1
5	Benefits of this facility, including uses to protect or enhance environmental quality, increase reliability of energy supply	Chapter 1.5.C Chapter 4.1 Chapter 6 Chapter 7 Chapter 8.1
6	Possible alternatives for satisfying demand, including increased efficiency and upgrading existing generation, load-management and distributed generation	Chapter 5.2 Chapter 8.1 Appendix D

Authority	Required Information	Location of Required Content
7	Policies, rules and regulations of other state and federal agencies and local governments	Chapter 2.2 Chapter 8
8	Feasible combination of energy conservation improvements, that can replace or compete with the facility	Chapter 5.2
Minn. Stat. §216B.243 subd. 3a and §216B.2422, subd. 4	Availability of renewable energy alternatives	Chapter 6 Chapter 8.1 Appendix D
Minn. Stat. §216B.1693	Clean Energy Technology Statute	Chapter 8.1
Minn. Stat. §216B.1694 subd. 2(a) (5)	Innovative Energy Project Statute	Chapter 8.3
In the Matter of Northern States Power Company d/b/a Excel Energy's Application for Approval of its 2005-2019 Resource Plan – Order dated7-28-06 Approving Plan Re: Docket No. 04-1752	Carbon risk analysis strategies	Chapter 1.7; 1.5.C Chapter 5 Chapter 6 Chapter 8.3

Appendix B: Xcel Energy System Demand and Capability Data

B.1 Overall Methodological 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, a Minnesota corporation (NSP), Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The NSP and NSPW Systems operate as an integrated system. The forecast is referred to as the 2007 Resource Plan Forecast (October 2007). The overall methodological framework is "model oriented."

B.2 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 or native 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 Energy Forecast (Native Energy Requirements) is developed by summing the jurisdictional class sales forecasts and adding the loss factor for each legal entity to the sum of the jurisdictional sales forecasts. The system loss factors for each legal entity are developed based on average historical losses After the Native Energy Requirements have been calculated, the 12 month sum of 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 NSP System.

B.3 Models Used

1. Residential Econometric Models. Sales to the residential sectors represented 27.0 percent of total NSP System electric sales in 2006. Residential sales are divided into with space heating and without space heating customer classes for each jurisdiction. Ordinary Least Squares (OLS) regression models using historical data are developed for each residential sector. A variety of independent variables are used in the models, including:

   - Number of customers;
   - 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 represented 41.6 percent of NSP System electric sales in 2006. The models are OLS regressions using historical data. The models include a combination of variables, including:

   - Number of small commercial and industrial customers;
   - Gross Metro Product 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 represented 27.8 percent of NSP System electric sales in 2006. The models are OLS regressions using historical data and a combination of variables, including :

   - Employment for respective jurisdiction;
   - Number of monthly billing days;
   - Indicator variables such as C&I reclassification.

4. Others. Sales to the "Others" sector represented 0.7 percent of NSP System electric sales in 2006. The Other 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 represented 2.9 percent of NSP System electric sales in 2006. 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.[1] An econometric model is developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including:

   - Weather normalized native energy requirements;
   - Peak producing weather by month;
   - Binary variables.

B.4 Methodology Strengths and Weaknesses

The strength of the process we use for this forecast is the richness of the information obtained during the analysis. Our 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 aware of the inherent risk that accompanies long-term forecasts. They must also, however, develop plans that are robust over a wide range of future outcomes.

B.5 Forecast Database

B.5.1 Data Definitions

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

B.5.1.1 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

B.5.1.2 Monthly MWh Sales Series

SLS(Juris)RX	Residential without space heating for given jurisdiction
SLS(Juris)RH	Residential with space heating for given jurisdiction
SLS(Juris)SCI	Small commercial and industrial for given jurisdiction
SLS(Juris)LCI	Large commercial and industrial for given jurisdiction

[1] The appropriate statistical tests related to the development of the peak demand and energy forecasts are too voluminous to include with this filing. Such information will be provided upon request.

B.5.1.3 Monthly Customer Series

NRX(Juris)	Residential without space heating for given jurisdiction
NRH(Juris)	Residential with space heating for given jurisdiction
NSCI(Juris)	Small commercial and industrial for given jurisdiction
NLCI(Juris)	Large commercial and industrial for given jurisdiction

B.5.1.4 Monthly Economic and Demographic Series

(Juris)HH	Number of Households in given jurisdiction
GMP(MSA)	Gross Metro Product for given metropolitan statistical area
EEA_(Juris)	Total non-farm employment in given jurisdiction
EM_(Juris)	Total manufacturing employment in given jurisdiction
EnonM_(Juris)	Total non-manufacturing employment in given jurisdiction
YP96(Juris)	Personal income in given jurisdiction

B.5.1.5 Monthly Data Variables used in Demand Model

THI12(Month)Cust	Temperature Humidity Index @12:00 noon multiplied by total retail customers
THI15(Month)Cust	Temperature Humidity Index @ 3:00 p.m. multiplied by total retail customers
HDDWtr	Normal Heating Degree Days on the day of the Peak multiplied by a binary variable for December, January and February
WNEnergy12MoSum	12 month rolling sum of the weather normalized net energy requirements

B.5.1.6 Monthly Weather Variables

R(Juris)H65(Month)	HDD base 65 for given jurisdiction and month
R(Juris)T65(Month)	THI DD base 65 for given jurisdiction and month

B.5.1.7 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

We use both internal and external data sources to create our MWh sales and MW peak demand forecast.

Historical MWh sales are taken from our internal company records, which are fed by our billing system. Historical coincident net peak demand data is also obtained through company records. The load management estimate, as determined through load research, is added to the net peak demand to derive the base peak demand.

Weather data (dry bulb temperature and dew points) are collected from a respected local meteorologist (Mr. Frank Watson) for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. 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 downloaded from Global Insight, Inc. data banks, and reflect the most recent values of the series at time of modeling.

B.6 Overview of Probability Distributions

We use 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 Gross State Product (MN GSP).

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 MN GSP 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 11,379 MW, then using the same econometric model, the Monte Carlo simulation method forecasts that there is a 90 percent probability that the 2022 peak demand will be less than 12,105 MW, or alternatively, a 10 percent chance that the peak will be less than 10,660 MW.

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

B.7 Data Adjustments and Assumptions

1. Weather Adjustments. We adjusted 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.

B.7.1 Assumptions and Special Information

The data used in our 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.

We believe that our process is a reasonable and workable one to use as a guide for our future energy and load requirements. The underlying assumptions used to prepare our 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. We assume "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 1987-2006. The variability of weather is an important source of uncertainty. Our energy 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. We use a historical average loss factor for each legal entity, and assume it will not change in the future.

B.8 Forecast Coordination

Xcel Energy reports its energy and peak demand forecasts to the Mid-Continent Area Power Pool (MAPP) as a requirement of membership. MAPP 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.

B.9 Methodology Changes

The risk assessment methodologies are the same methodologies that were used to develop the forecasts and risk assessment presented in the Company's forecast in the November 2006 Base Load Certificate of Need Filing[2] and the 2004 Resource Plan filing, with the exception of two

[2] The last two Certificates of Need filed by Xcel Energy - the Base Load and the Grand Meadow Wind Farm CONs (Dockets E002/CN-06-1518 and E002/CN-07-873 respectively) both used the same forecast.

changes. The first is a change in the number of historical data observations that were included in the peak demand forecast model. For the 2004 Resource Plan filing and the November 2006 Base Load Certificate of Need Filing, the peak demand model used explanatory data beginning in 1993. In the forecast used in this filing and the 2007 Resource Plan ("2007 Resource Plan Forecast") the peak demand model utilized data beginning in 1998. The second is how DSM is accounted for as explained below.

B.9.1 Demand-Side Management Programs

Our 2007 Resource Plan outlines a change we made to how we previously accounted for demand-side management ("DSM") in our resource plan. In past forecasts, embedded DSM from past programs was included in the forecast, but the forecast did not incorporate estimated savings from future DSM programs. Future DSM savings were made as an adjustment during modeling. In determining the forecasts in the new Resource Plan, we made adjustments to the forecasts to account for future DSM savings and no longer make adjustments during modeling.

The regression model results for the residential and commercial and industrial classes are reduced to account for the expected incremental impacts of DSM programs. An annual forecast of the impact of new DSM programs (excluding Saver's Switch) is developed by our DSM Regulatory Strategy and Planning Department. The impacts are then 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 2006 are assumed to be embedded in the historical data, so only new program installations are included in the DSM adjustment.

The DSM adjustment was made to reflect compliance with Minnesota's new Renewable Energy Standard ("RES") requirements outlined in the Next Generation Energy Act of 2007. The Act seeks to achieve a statewide energy conservation goal of 1.5 percent of retail sales, recognizing that both direct and indirect energy conservation programs can help achieve this goal, and requires utilities to achieve a minimum amount of savings from direct programs at 1.0 percent by 2010. Utilities may include "indirect & other" projects to provide energy savings above the required 1.0 percent. The Company's current Conservation Improvement Program ("CIP") activities currently reduce annual retail sales by an estimated 0.8 percent. To comply with the RES, we proposed in the 2007 Resource Plan a 1.1 percent energy reduction plan and have assumed that energy savings goal in the DSM adjustment. The 1.1 percent energy savings is subtracted from the Minnesota jurisdictional sales forecast. The system load management savings estimates at peak demand are then applied to arrive at a "net" peak from the "base" peak.

B.10 Comparison Between Current and Previous Forecast

Due to our experiences in obtaining short-term capacity purchases, in 2004 we switched from using the 50 percent demand (MW) probability forecast for capacity planning to using the 90 percent demand (MW) probability forecast. In doing so, we also modified how we account for estimated short-term purchases available from the market and now include them in our generation

assessment. This methodology change has been used in all Certificates of Need submitted since then and also in the recently submitted 2007 Resource Plan filing.

Under this modified approach, we determined the amount of accredited short-term resources that we expected we would reasonably be able to obtain in any given season. We have determined that this accredited short-term resources capacity is 750 MW based on the transmission paths that we currently control or believe that we could control, as well as the estimated transfer capability into MAPP from the rest of MISO. We set this amount as our baseline level of short-term capacity and add it to our total capability to determine the gap between our load and resources. We then compare our increased capability against our 90 percent forecast level to ensure that we were acquiring sufficient resources to meet our actual peak.

Planning for capacity to the 90 percent forecast enables us to more confidently meet our "obligation to serve" as required by Minn. Stat §216B.04.

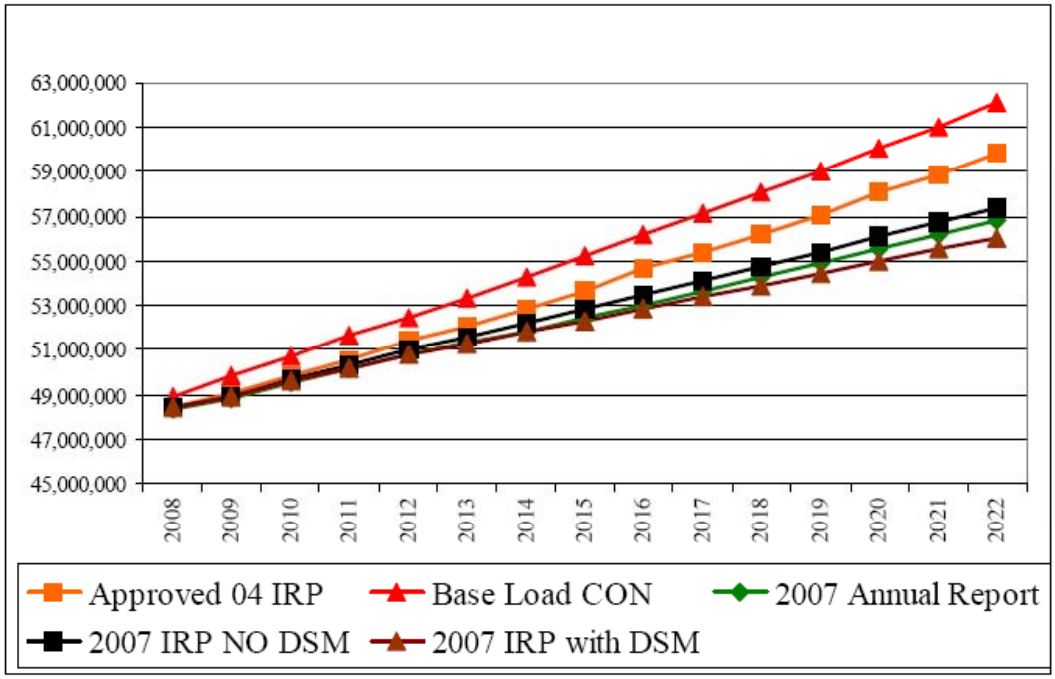
B.10.1 Energy Comparison (50th Percentile Forecast)

In the forecast used in this filing, ("2007 Resource Plan" forecast or "current forecast" – which includes the 1.1. percent DSM adjustment), the 2010 estimate of native energy requirements is 49,573,779 MWh compared to 50,705,794 MWh that was estimated in the forecast used in the 2006 Base Load CON Forecast (referred to as the "previous" forecast).

The current forecast of energy increases at an average annual rate of 1.1 percent, while the previous forecast increased at an average annual rate of 1.7 percent. This difference is affected by how DSM is handled though between the two forecasts, as well as new loss factors and lower than expected 2006 actual sales as compared to forecast.

For 2010, the current forecast is 1,132,015 MWh, or 2.2 percent lower than the previous forecast. The 2015 estimate of native energy requirements in the current forecast is 52,314,897 MWh compared to 55,244,670 MWh that was estimated in the previous forecast. For 2015, the current forecast is 2,929,733 MWh, or 5.3 percent lower than the previous forecast. Comparisons of the base energy forecasts (50th percentile forecast) with and without DSM referenced above are found in Figure B.10.1. Copies of the 50th percentile forecast and the 90th percentile forecasts in graphic and tabular format are found in section B.12 Forecast Comparisons for comparison purposes.

Figure B.10.1
Comparison of Current and Previous Energy Forecasts

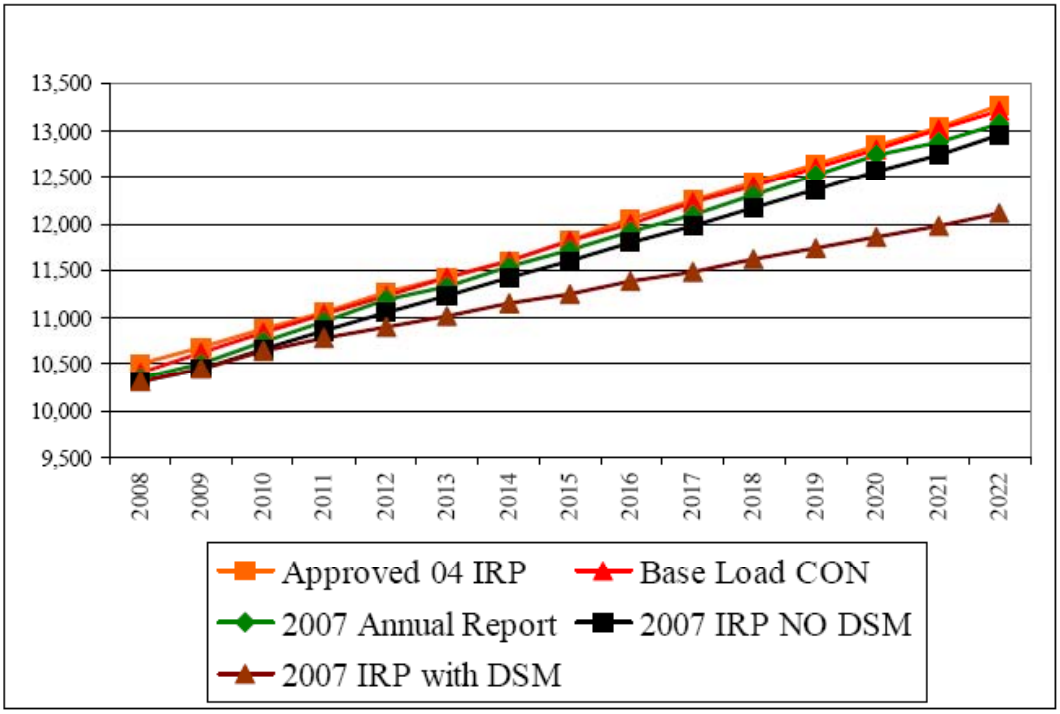


B.10.2 Peak Demand Comparison (90th Percentile Forecast)

In the current forecast, which includes a 1.1% DSM Adjustment, the 2010 estimate of base peak demand is 10,630 MW compared to 10,832 MW that was estimated in the previous forecast. For 2010, the current forecast is 202 MW, or 1.9 percent lower than the previous forecast. The 2015 estimate of Peak Demand in the current forecast is 11,250 MW compared to 11,816 MW that was estimated in the previous forecast. For 2015, the current forecast is 566 MW, or 4.8 percent lower than the previous forecast.

The current forecast of base peak demand increases at an average annual rate of 1.2 percent, while the previous forecast increased at an average annual rate of 1.7 percent. Comparisons of the current and previous base peak demand forecasts (90th percentile forecast) are found in Figure B.10.2. Copies of the 50th percentile forecast and the 90th percentile forecasts in graphic and tabular format are found in Section B.12 Forecast Comparisons for comparison purposes.

Figure B.10.2
Comparison of Current and Previous Demand Forecasts



Figures 10.1 and 10.2 above compare the peak demand and energy of the Company's current forecast with the forecasts approved in the 2004 Resource Plan, the Base Load CON filed in November of 2006 and the Electric Utility Annual Report filed in mid 2007. We have also included a comparison of the energy and demand forecasts with and without DSM for direct comparison to previous forecasts (which did not include the DSM adjustments). Figure 10.1 indicates that the energy forecast (without DSM) is slightly higher than the forecast reported in our 2007 Annual Electric Utility Report, but lower than the forecast approved in our 2004 Resource Plan. This is due to a reduction in some economic indicators since the 2004 Resource Plan forecast was produced. Figure 10.2 indicates that there has been very little change in the demand forecast since previous forecasts. The new demand forecast without DSM is slightly lower than the previous demand forecasts.

After accounting for the DSM, the average annual growth rates in the forecasts are similar to the average annual growth rates of previous forecasts. The change in DSM methodology reduces the forecast needs, but other factors also contribute, including updated loss factors that are lower than previous forecasts, some key variables being less optimistic in this forecast, and weather normalized actual sales for 2006, which were lower than forecast.

B.11 FORECASTING BASE LOAD DATA SET

B.11.1 Annual Electric Consumption

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Annual Electric Consumption (MWh)

	Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	Total	Loss and Company Use	Total Native Requirements
1996	*NA*	*NA*	9,846,683	6,090,893	*NA*	18,559,078	162,829	901,219	35,560,702	3,351,548	38,912,250
1997	*NA*	*NA*	9,790,326	5,906,731	*NA*	19,322,224	168,560	542,548	35,730,389	3,770,864	39,501,253
1998	*NA*	*NA*	10,126,591	5,999,443	*NA*	20,078,399	169,440	822,445	37,196,318	3,495,771	40,692,089
1999	*NA*	*NA*	10,400,723	6,132,930	*NA*	20,290,272	170,527	791,416	37,785,868	3,430,442	41,216,310
2000	*NA*	*NA*	10,768,710	6,637,476	*NA*	20,684,275	172,961	823,692	39,087,114	3,154,430	42,241,544
2001	*NA*	*NA*	11,016,223	15,716,290	*NA*	11,735,057	176,470	859,435	39,503,475	3,326,283	42,829,758
2002	*NA*	*NA*	11,656,830	14,794,020	*NA*	12,870,013	177,553	945,011	40,443,427	3,336,657	43,780,084
2003	*NA*	*NA*	11,662,067	16,579,354	*NA*	11,443,959	177,054	954,164	40,816,598	2,916,803	43,733,401
2004	*NA*	*NA*	11,402,028	16,644,896	*NA*	11,708,988	188,087	1,098,171	41,042,169	2,347,910	43,390,079
2005	*NA*	*NA*	12,105,594	18,272,282	*NA*	11,110,675	184,643	1,303,511	42,976,705	1,780,450	44,757,155
2006	*NA*	*NA*	12,147,178	18,276,180	*NA*	11,354,870	192,808	1,651,632	43,622,668	2,495,690	46,118,358
2007	*NA*	*NA*	12,235,435	18,422,074	*NA*	11,654,626	193,779	1,672,093	44,178,008	3,534,712	47,712,720
2008	*NA*	*NA*	12,463,570	18,741,587	*NA*	11,866,069	195,746	1,523,642	44,790,612	3,582,601	48,373,213
2009	*NA*	*NA*	12,676,493	18,981,326	*NA*	12,091,019	197,743	1,314,487	45,261,068	3,620,958	48,882,025
2010	*NA*	*NA*	12,929,132	19,202,375	*NA*	12,242,683	199,771	1,328,577	45,902,538	3,671,241	49,573,779
2011	*NA*	*NA*	13,176,454	19,409,643	*NA*	12,332,924	201,831	1,341,159	46,462,011	3,715,285	50,177,296
2012	*NA*	*NA*	13,438,778	19,607,058	*NA*	12,405,475	203,925	1,353,092	47,008,328	3,756,382	50,764,710
2013	*NA*	*NA*	13,650,692	19,795,807	*NA*	12,468,612	206,053	1,362,114	47,483,278	3,795,850	51,279,128
2014	*NA*	*NA*	13,872,521	19,977,834	*NA*	12,526,231	208,215	1,371,390	47,956,191	3,833,127	51,789,318
2015	*NA*	*NA*	14,098,668	20,163,457	*NA*	12,589,898	210,414	1,380,892	48,443,329	3,871,568	52,314,897
2016	*NA*	*NA*	14,348,678	20,352,722	*NA*	12,647,809	212,649	1,390,660	48,952,517	3,909,774	52,862,291
2017	*NA*	*NA*	14,557,183	20,537,303	*NA*	12,716,782	214,922	1,400,597	49,426,788	3,949,241	53,376,029
2018	*NA*	*NA*	14,788,499	20,725,003	*NA*	12,782,520	217,234	1,410,813	49,924,068	3,988,475	53,912,542
2019	*NA*	*NA*	15,019,924	20,914,011	*NA*	12,850,648	219,586	1,421,279	50,425,448	4,028,091	54,453,539
2020	*NA*	*NA*	15,266,853	21,097,745	*NA*	12,922,115	221,979	1,432,038	50,940,731	4,066,747	55,007,477
2021	*NA*	*NA*	15,470,229	21,275,268	*NA*	13,001,600	224,415	1,442,992	51,414,503	4,106,184	55,520,687
2022	*NA*	*NA*	15,698,514	21,457,477	*NA*	13,076,931	226,894	1,454,253	51,914,068	4,145,626	56,059,694

B.11.1 Annual Electric Consumption – Continued

NSPM 2007 Resource Plan

Xcel Energy
State of Minnesota
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Annual Electric Consumption (MWh)

	Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	Total Retail
1996	*NA*	*NA*	6,958,068	4,489,648	*NA*	14,804,136	120,454	130,446	26,502,752
1997	*NA*	*NA*	6,969,183	4,345,002	*NA*	15,381,278	125,384	123,757	26,944,604
1998	*NA*	*NA*	7,281,178	4,380,415	*NA*	15,941,944	126,008	117,103	27,846,648
1999	*NA*	*NA*	7,501,113	4,470,016	*NA*	16,078,335	125,845	116,404	28,291,713
2000	*NA*	*NA*	7,785,498	4,843,242	*NA*	16,401,555	128,075	115,585	29,273,955
2001	*NA*	*NA*	8,031,583	13,039,381	*NA*	8,355,790	130,612	117,940	29,675,306
2002	*NA*	*NA*	8,487,490	12,080,326	*NA*	9,369,199	130,657	109,500	30,177,172
2003	*NA*	*NA*	8,482,571	12,300,171	*NA*	9,387,479	129,473	118,286	30,417,981
2004	*NA*	*NA*	8,289,361	12,375,215	*NA*	9,489,401	139,813	109,413	30,403,203
2005	*NA*	*NA*	8,841,946	13,640,413	*NA*	8,993,804	135,989	100,894	31,713,045
2006	*NA*	*NA*	8,876,545	13,677,161	*NA*	9,129,744	143,664	99,422	31,926,536
2007	*NA*	*NA*	8,906,363	13,703,963	*NA*	9,345,179	143,423	101,588	32,200,517
2008	*NA*	*NA*	9,094,793	13,987,609	*NA*	9,550,680	144,656	101,623	32,879,362
2009	*NA*	*NA*	9,265,319	14,182,109	*NA*	9,747,577	145,900	101,588	33,442,494
2010	*NA*	*NA*	9,471,993	14,349,326	*NA*	9,868,097	147,155	101,588	33,938,159
2011	*NA*	*NA*	9,673,218	14,510,516	*NA*	9,930,964	148,421	101,588	34,364,708
2012	*NA*	*NA*	9,888,700	14,658,365	*NA*	9,976,815	149,697	101,623	34,775,201
2013	*NA*	*NA*	10,057,047	14,806,634	*NA*	10,016,272	150,985	101,588	35,132,526
2014	*NA*	*NA*	10,234,785	14,940,962	*NA*	10,048,588	152,283	101,588	35,478,206
2015	*NA*	*NA*	10,416,662	15,077,232	*NA*	10,086,163	153,593	101,588	35,835,238
2016	*NA*	*NA*	10,622,204	15,211,838	*NA*	10,116,198	154,914	101,623	36,206,776
2017	*NA*	*NA*	10,787,353	15,350,131	*NA*	10,157,620	156,246	101,588	36,552,938
2018	*NA*	*NA*	10,974,984	15,486,011	*NA*	10,192,334	157,590	101,588	36,912,506
2019	*NA*	*NA*	11,162,424	15,619,841	*NA*	10,227,951	158,945	101,588	37,270,748
2020	*NA*	*NA*	11,363,569	15,741,919	*NA*	10,265,692	160,312	101,623	37,633,114
2021	*NA*	*NA*	11,523,331	15,866,801	*NA*	10,312,843	161,690	101,588	37,966,254
2022	*NA*	*NA*	11,707,438	15,990,601	*NA*	10,355,137	163,081	101,588	38,317,845

B.11.2 Number of Customers By Class

NSPM 2007 Resource Plan

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

Number of Customers

	Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	Total
1996	*NA*	*NA*	1,234,321	142,008	*NA*	8,596	2,910	2,849	1,390,684
1997	*NA*	*NA*	1,280,816	148,848	*NA*	9,653	3,371	2,905	1,445,593
1998	*NA*	*NA*	1,292,243	150,918	*NA*	10,144	3,331	2,912	1,459,548
1999	*NA*	*NA*	1,313,048	155,891	*NA*	10,423	2,330	2,895	1,484,587
2000	*NA*	*NA*	1,328,936	157,909	*NA*	9,382	3,623	2,832	1,502,682
2001	*NA*	*NA*	1,345,077	170,154	*NA*	752	3,836	2,833	1,522,652
2002	*NA*	*NA*	1,361,938	173,240	*NA*	763	4,009	2,838	1,542,788
2003	*NA*	*NA*	1,379,851	175,484	*NA*	753	3,784	2,810	1,562,682
2004	*NA*	*NA*	1,404,993	179,326	*NA*	769	4,299	2,813	1,592,200
2005	*NA*	*NA*	1,389,605	176,358	*NA*	616	4,290	2,716	1,573,585
2006	*NA*	*NA*	1,413,729	180,050	*NA*	599	4,430	2,746	1,601,554
2007	*NA*	*NA*	1,427,109	182,067	*NA*	616	4,508	2,734	1,617,034
2008	*NA*	*NA*	1,442,310	184,642	*NA*	616	4,597	2,712	1,634,877
2009	*NA*	*NA*	1,458,898	187,332	*NA*	616	4,696	2,690	1,654,232
2010	*NA*	*NA*	1,476,028	190,075	*NA*	616	4,799	2,669	1,674,187
2011	*NA*	*NA*	1,492,801	192,713	*NA*	616	4,900	2,648	1,693,678
2012	*NA*	*NA*	1,509,075	195,275	*NA*	616	4,999	2,627	1,712,591
2013	*NA*	*NA*	1,524,929	197,769	*NA*	616	5,094	2,606	1,731,013
2014	*NA*	*NA*	1,540,505	200,227	*NA*	616	5,188	2,585	1,749,122
2015	*NA*	*NA*	1,556,433	202,738	*NA*	616	5,284	2,565	1,767,636
2016	*NA*	*NA*	1,572,448	205,257	*NA*	616	5,381	2,545	1,786,247
2017	*NA*	*NA*	1,588,406	207,766	*NA*	616	5,477	2,525	1,804,790
2018	*NA*	*NA*	1,604,723	210,334	*NA*	616	5,575	2,505	1,823,754
2019	*NA*	*NA*	1,620,658	212,850	*NA*	616	5,671	2,486	1,842,282
2020	*NA*	*NA*	1,636,294	215,323	*NA*	616	5,765	2,467	1,860,464
2021	*NA*	*NA*	1,652,011	217,809	*NA*	616	5,860	2,448	1,878,743
2022	*NA*	*NA*	1,667,930	220,324	*NA*	616	5,956	2,429	1,897,255

B.11.2 Number of Customers By Class – Continued

NSPM 2007 Resource Plan

Xcel Energy
State of Minnesota Electric
Certificate of Need Filing
Median Forecast (50th Percentile)

Number of Customers

	Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	Total
1996	*NA*	*NA*	928,009	95,911	*NA*	6,217	2,004	2,192	1,034,333
1997	*NA*	*NA*	970,762	102,191	*NA*	7,065	2,470	2,257	1,084,745
1998	*NA*	*NA*	977,119	103,315	*NA*	7,494	2,404	2,232	1,092,564
1999	*NA*	*NA*	993,337	107,118	*NA*	7,908	1,424	2,214	1,112,001
2000	*NA*	*NA*	1,006,613	107,679	*NA*	6,952	2,629	2,160	1,126,033
2001	*NA*	*NA*	1,017,202	116,720	*NA*	603	2,791	2,162	1,139,478
2002	*NA*	*NA*	1,029,634	118,687	*NA*	608	2,945	2,170	1,154,044
2003	*NA*	*NA*	1,043,231	120,223	*NA*	595	2,712	2,142	1,168,903
2004	*NA*	*NA*	1,062,137	122,902	*NA*	586	3,188	2,140	1,190,953
2005	*NA*	*NA*	1,047,452	119,935	*NA*	485	3,151	2,093	1,173,116
2006	*NA*	*NA*	1,065,337	122,406	*NA*	461	3,276	2,062	1,193,542
2007	*NA*	*NA*	1,075,599	123,562	*NA*	482	3,331	2,055	1,205,028
2008	*NA*	*NA*	1,087,686	125,157	*NA*	482	3,402	2,033	1,218,760
2009	*NA*	*NA*	1,101,080	126,924	*NA*	482	3,484	2,011	1,233,982
2010	*NA*	*NA*	1,114,994	128,760	*NA*	482	3,570	1,990	1,249,796
2011	*NA*	*NA*	1,128,548	130,548	*NA*	482	3,654	1,969	1,265,202
2012	*NA*	*NA*	1,141,698	132,283	*NA*	482	3,736	1,948	1,280,147
2013	*NA*	*NA*	1,154,471	133,969	*NA*	482	3,816	1,927	1,294,665
2014	*NA*	*NA*	1,166,977	135,619	*NA*	482	3,894	1,906	1,308,878
2015	*NA*	*NA*	1,179,834	137,315	*NA*	482	3,974	1,886	1,323,492
2016	*NA*	*NA*	1,192,793	139,025	*NA*	482	4,055	1,866	1,338,221
2017	*NA*	*NA*	1,205,720	140,731	*NA*	482	4,136	1,846	1,352,915
2018	*NA*	*NA*	1,219,050	142,489	*NA*	482	4,219	1,826	1,368,068
2019	*NA*	*NA*	1,231,996	144,197	*NA*	482	4,300	1,807	1,382,783
2020	*NA*	*NA*	1,244,656	145,868	*NA*	482	4,379	1,788	1,397,173
2021	*NA*	*NA*	1,257,422	147,552	*NA*	482	4,459	1,769	1,411,684
2022	*NA*	*NA*	1,270,488	149,276	*NA*	482	4,541	1,750	1,426,537

B.11.3 Annual Base Peak Demand By Customer Class

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Annual Base Peak Demand (Mw) by Customer Class

		Farm	Irrigation	Residential	Commercial	Mining	Industrial	Street Lighting	Other	System Peak Demand Mw
NET PEAK	**1996**	71	*NA*	2,421	1,402	10	3,416	*NA*	168	7,488
	1997	68	*NA*	2,335	1,318	11	3,466	*NA*	155	7,353
	1998	68	*NA*	2,450	1,345	9	3,638	*NA*	149	7,659
	1999	*NA*	*NA*	2,669	1,405	*NA*	3,756	*NA*	160	7,990
	2000	*NA*	*NA*	2,655	1,461	*NA*	3,674	*NA*	146	7,936
	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*	3,419	3,545	*NA*	2,150	*NA*	312	9,427
	2008	*NA*	*NA*	3,532	3,661	*NA*	2,221	*NA*	323	9,737
BASE PEAK	**2009**	*NA*	*NA*	3,584	3,716	*NA*	2,254	*NA*	327	9,881
	2010	*NA*	*NA*	3,649	3,783	*NA*	2,295	*NA*	333	10,060
	2011	*NA*	*NA*	3,696	3,832	*NA*	2,325	*NA*	338	10,190
	2012	*NA*	*NA*	3,740	3,877	*NA*	2,352	*NA*	342	10,310
	2013	*NA*	*NA*	3,777	3,916	*NA*	2,376	*NA*	345	10,414
	2014	*NA*	*NA*	3,820	3,960	*NA*	2,402	*NA*	349	10,531
	2015	*NA*	*NA*	3,859	4,000	*NA*	2,427	*NA*	352	10,639
	2016	*NA*	*NA*	3,899	4,041	*NA*	2,452	*NA*	356	10,748
	2017	*NA*	*NA*	3,933	4,078	*NA*	2,474	*NA*	359	10,844
	2018	*NA*	*NA*	3,977	4,123	*NA*	2,501	*NA*	363	10,965
	2019	*NA*	*NA*	4,016	4,163	*NA*	2,526	*NA*	367	11,072
	2020	*NA*	*NA*	4,054	4,202	*NA*	2,549	*NA*	370	11,176
	2021	*NA*	*NA*	4,086	4,236	*NA*	2,570	*NA*	373	11,265
	2022	*NA*	*NA*	4,128	4,279	*NA*	2,596	*NA*	377	11,379

The historical peaks by class in this table sum to the Net (interrupted) peak rather than 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 Base peaks. Therefore, the historical system values do not tie between Table B.11.3 and Table B.11.4.

B.11.4 Monthly Native Energy and Demand Requirements

NSPM 2007 Resource Plan

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-96	3,409,149	5,813	31	78.8%
Feb-96	3,122,223	5,955	29	75.3%
Mar-96	3,222,120	5,568	31	77.8%
Apr-96	2,947,510	5,129	30	79.8%
May-96	2,992,877	5,225	31	77.0%
Jun-96	3,351,580	7,624	30	61.1%
Jul-96	3,434,739	7,325	31	63.0%
Aug-96	3,636,362	7,687	31	63.6%
Sep-96	3,146,268	7,093	30	61.6%
Oct-96	3,124,517	5,417	31	77.5%
Nov-96	3,153,288	5,666	30	77.3%
Dec-96	3,371,617	5,869	31	77.2%
Jan-97	3,495,291	5,856	31	80.2%
Feb-97	3,041,215	5,555	28	81.5%
Mar-97	3,191,399	5,332	31	80.4%
Apr-97	2,882,858	5,189	30	77.2%
May-97	2,991,849	5,099	31	78.9%
Jun-97	3,437,381	7,271	30	65.7%
Jul-97	3,786,351	7,767	31	65.5%
Aug-97	3,587,471	6,716	31	71.8%
Sep-97	3,254,699	6,141	30	73.6%
Oct-97	3,263,444	5,864	31	74.8%
Nov-97	3,192,368	5,631	30	78.7%
Dec-97	3,376,927	5,787	31	78.4%
Jan-98	3,448,048	5,877	31	78.9%
Feb-98	3,022,832	5,608	28	80.2%
Mar-98	3,299,215	5,506	31	80.5%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

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
Apr-98	3,001,079	5,251	30	79.4%
May-98	3,328,372	7,142	31	62.6%
Jun-98	3,441,411	7,099	30	67.3%
Jul-98	3,979,545	8,179	31	65.4%
Aug-98	3,922,566	7,268	31	72.5%
Sep-98	3,455,777	6,682	30	71.8%
Oct-98	3,237,478	5,466	31	79.6%
Nov-98	3,136,287	5,598	30	77.8%
Dec-98	3,419,479	6,187	31	74.3%
Jan-99	3,585,110	6,138	31	78.5%
Feb-99	3,061,339	5,670	28	80.3%
Mar-99	3,255,083	5,470	31	80.0%
Apr-99	3,025,556	5,169	30	81.3%
May-99	3,218,400	5,806	31	74.5%
Jun-99	3,581,246	7,495	30	66.4%
Jul-99	4,250,059	8,735	31	65.4%
Aug-99	3,850,480	7,814	31	66.2%
Sep-99	3,363,251	7,675	30	60.9%
Oct-99	3,291,632	5,501	31	80.4%
Nov-99	3,182,850	5,885	30	75.1%
Dec-99	3,551,303	6,422	31	74.3%
Jan-00	3,586,329	5,985	31	80.5%
Feb-00	3,042,834	5,818	29	75.1%
Mar-00	3,306,723	5,409	31	82.2%
Apr-00	3,147,526	5,422	30	80.6%
May-00	3,439,965	6,563	31	70.4%
Jun-00	3,550,819	7,545	30	65.4%
Jul-00	4,060,805	7,816	31	69.8%
Aug-00	4,151,284	8,189	31	68.1%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

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
Sep-00	3,407,477	6,720	30	70.4%
Oct-00	3,362,896	5,675	31	79.6%
Nov-00	3,391,085	6,053	30	77.8%
Dec-00	3,793,801	6,557	31	77.8%
Jan-01	3,639,735	6,144	31	79.6%
Feb-01	3,327,152	6,112	28	81.0%
Mar-01	3,414,582	5,624	31	81.6%
Apr-01	3,150,897	5,594	30	78.2%
May-01	3,412,524	7,200	31	63.7%
Jun-01	3,728,184	8,061	30	64.2%
Jul-01	4,347,736	9,001	31	64.9%
Aug-01	4,271,909	9,236	31	62.2%
Sep-01	3,382,565	6,924	30	67.9%
Oct-01	3,361,640	5,740	31	78.7%
Nov-01	3,266,364	6,005	30	75.5%
Dec-01	3,526,470	6,012	31	78.8%
Jan-02	3,622,279	6,187	31	78.7%
Feb-02	3,163,001	5,872	28	80.2%
Mar-02	3,548,998	5,946	31	80.2%
Apr-02	3,272,927	6,221	30	73.1%
May-02	3,348,877	7,013	31	64.2%
Jun-02	3,937,321	8,281	30	66.0%
Jul-02	4,564,178	8,924	31	68.7%
Aug-02	4,024,109	7,465	31	72.5%
Sep-02	3,707,000	8,192	30	62.8%
Oct-02	3,529,247	5,929	31	80.0%
Nov-02	3,411,544	6,070	30	78.1%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

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
Dec-02	3,650,602	6,386	31	76.8%
Jan-03	3,803,608	6,371	31	80.2%
Feb-03	3,384,792	6,236	28	80.8%
Mar-03	3,527,760	5,954	31	79.6%
Apr-03	3,287,588	5,755	30	79.3%
May-03	3,310,402	5,892	31	75.5%
Jun-03	3,649,429	7,760	30	65.3%
Jul-03	4,218,642	8,066	31	70.3%
Aug-03	4,354,499	8,868	31	66.0%
Sep-03	3,561,053	7,819	30	63.3%
Oct-03	3,486,682	6,128	31	76.5%
Nov-03	3,425,474	6,136	30	77.5%
Dec-03	3,723,471	6,497	31	77.0%
Jan-04	3,943,515	6,653	31	79.7%
Feb-04	3,394,926	6,320	29	77.2%
Mar-04	3,564,881	5,941	31	80.7%
Apr-04	3,206,338	5,749	30	77.5%
May-04	3,448,170	6,240	31	74.3%
Jun-04	3,668,748	8,106	30	62.9%
Jul-04	4,191,224	8,665	31	65.0%
Aug-04	3,904,279	7,920	31	66.3%
Sep-04	3,826,641	8,029	30	66.2%
Oct-04	3,536,969	5,937	31	80.1%
Nov-04	3,502,014	6,224	30	78.1%
Dec-04	4,033,963	6,873	31	78.9%
Jan-05	3,882,624	6,636	31	78.6%
Feb-05	3,371,444	6,222	28	80.6%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Mar-05	3,638,633	5,996	31	81.6%
Apr-05	3,312,891	6,017	30	76.5%
May-05	3,458,752	6,055	31	76.8%
Jun-05	4,129,640	9,072	30	63.2%
Jul-05	4,643,177	8,945	31	69.8%
Aug-05	4,354,721	9,104	31	64.3%
Sep-05	3,785,401	7,512	30	70.0%
Oct-05	3,666,458	7,253	31	67.9%
Nov-05	3,526,905	6,466	30	75.8%
Dec-05	3,916,529	6,833	31	77.0%
Jan-06	4,080,982	6,689	31	82.0%
Feb-06	3,578,106	6,385	28	83.4%
Mar-06	3,671,298	6,093	31	81.0%
Apr-06	3,462,513	6,062	30	79.3%
May-06	3,663,096	7,024	31	70.1%
Jun-06	4,002,806	8,596	30	64.7%
Jul-06	4,562,949	9,314	31	65.8%
Aug-06	4,502,426	9,035	31	67.0%
Sep-06	3,829,688	8,268	30	64.3%
Oct-06	3,768,048	6,304	31	80.3%
Nov-06	3,755,432	6,387	30	81.7%
Dec-06	4,063,998	6,808	31	80.2%
Jan-07	4,032,030	6,597	31	82.1%
Feb-07	3,541,786	6,740	28	78.2%
Mar-07	3,930,805	6,297	31	83.9%
Apr-07	3,491,186	5,985	30	81.0%
May-07	3,843,306	7,273	31	71.0%
Jun-07	4,241,697	9,130	30	64.5%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Jul-07	4,660,851	9,427	31	66.5%
Aug-07	4,574,712	8,820	31	69.7%
Sep-07	3,760,865	8,093	30	64.5%
Oct-07	3,808,848	6,378	31	80.3%
Nov-07	3,781,794	6,486	30	81.0%
Dec-07	4,044,840	6,941	31	78.3%
Jan-08	4,048,374	6,804	31	80.0%
Feb-08	3,756,007	6,602	29	81.7%
Mar-08	4,097,462	6,234	31	88.3%
Apr-08	3,581,599	6,108	30	81.4%
May-08	3,961,273	7,336	31	72.6%
Jun-08	4,264,234	9,062	30	65.4%
Jul-08	4,753,717	9,737	31	65.6%
Aug-08	4,509,999	9,294	31	65.2%
Sep-08	3,624,922	8,300	30	60.7%
Oct-08	3,853,254	6,455	31	80.2%
Nov-08	3,881,438	6,566	30	82.1%
Dec-08	4,040,935	7,024	31	77.3%
Jan-09	4,057,907	6,892	31	79.1%
Feb-09	3,667,639	6,679	28	81.7%
Mar-09	4,183,623	6,298	31	89.3%
Apr-09	3,625,775	6,168	30	81.6%
May-09	3,954,579	7,445	31	71.4%
Jun-09	4,320,987	9,214	30	65.1%
Jul-09	4,793,735	9,881	31	65.2%
Aug-09	4,536,994	9,439	31	64.6%
Sep-09	3,808,954	8,500	30	62.2%
Oct-09	3,886,988	6,514	31	80.2%
Nov-09	3,932,047	6,620	30	82.5%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Dec-09	4,112,797	7,093	31	77.9%
Jan-10	4,113,762	6,946	31	79.6%
Feb-10	3,734,039	6,735	29	79.7%
Mar-10	4,261,141	6,346	31	90.2%
Apr-10	3,685,005	6,217	30	82.3%
May-10	4,017,079	7,571	31	71.3%
Jun-10	4,378,924	9,388	30	64.8%
Jul-10	4,846,619	10,060	31	64.8%
Aug-10	4,584,122	9,619	31	64.1%
Sep-10	3,855,009	8,697	30	61.6%
Oct-10	3,939,719	6,565	31	80.7%
Nov-10	3,988,476	6,673	30	83.0%
Dec-10	4,169,884	7,153	31	78.4%
Jan-11	4,161,358	6,979	31	80.1%
Feb-11	3,786,436	6,765	28	83.3%
Mar-11	4,322,479	6,369	31	91.2%
Apr-11	3,735,080	6,238	30	83.2%
May-11	4,070,465	7,660	31	71.4%
Jun-11	4,431,331	9,519	30	64.7%
Jul-11	4,897,367	10,190	31	64.6%
Aug-11	4,630,793	9,751	31	63.8%
Sep-11	3,897,804	8,862	30	61.1%
Oct-11	3,986,633	6,584	31	81.4%
Nov-11	4,037,785	6,691	30	83.8%
Dec-11	4,219,765	7,176	31	79.0%
Jan-12	4,210,136	7,004	31	80.8%
Feb-12	3,967,605	6,787	29	84.0%
Mar-12	4,331,690	6,381	31	91.2%
Apr-12	3,776,293	6,248	30	83.9%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
May-12	4,169,346	7,740	31	72.4%
Jun-12	4,475,697	9,639	30	64.5%
Jul-12	4,948,686	10,310	31	64.5%
Aug-12	4,685,762	9,874	31	63.8%
Sep-12	3,788,405	9,002	30	58.4%
Oct-12	4,056,480	6,586	31	82.8%
Nov-12	4,096,992	6,694	30	85.0%
Dec-12	4,257,618	7,184	31	79.7%
Jan-13	4,249,762	7,012	31	81.5%
Feb-13	3,876,018	6,794	28	84.9%
Mar-13	4,427,064	6,391	31	93.1%
Apr-13	3,821,958	6,257	30	84.8%
May-13	4,164,523	7,804	31	71.7%
Jun-13	4,527,857	9,745	30	64.5%
Jul-13	4,996,934	10,414	31	64.5%
Aug-13	4,724,620	9,978	31	63.6%
Sep-13	3,980,051	9,167	30	60.3%
Oct-13	4,073,404	6,608	31	82.9%
Nov-13	4,127,171	6,713	30	85.4%
Dec-13	4,309,766	7,210	31	80.3%
Jan-14	4,290,845	7,040	31	81.9%
Feb-14	3,915,835	6,819	29	82.5%
Mar-14	4,473,538	6,407	31	93.9%
Apr-14	3,860,460	6,271	30	85.5%
May-14	4,206,591	7,884	31	71.7%
Jun-14	4,572,042	9,862	30	64.4%
Jul-14	5,044,704	10,531	31	64.4%
Aug-14	4,770,149	10,098	31	63.5%
Sep-14	4,019,135	9,304	30	60.0%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Oct-14	4,114,722	6,614	31	83.6%
Nov-14	4,169,272	6,721	30	86.2%
Dec-14	4,352,024	7,222	31	81.0%
Jan-15	4,332,760	7,053	31	82.6%
Feb-15	3,955,841	6,831	28	86.2%
Mar-15	4,520,234	6,413	31	94.7%
Apr-15	3,900,144	6,277	30	86.3%
May-15	4,250,096	7,952	31	71.8%
Jun-15	4,618,055	9,969	30	64.3%
Jul-15	5,094,659	10,639	31	64.4%
Aug-15	4,817,943	10,209	31	63.4%
Sep-15	4,059,927	9,447	30	59.7%
Oct-15	4,157,350	6,621	31	84.4%
Nov-15	4,212,518	6,727	30	87.0%
Dec-15	4,395,371	7,234	31	81.7%
Jan-16	4,379,154	7,067	31	83.3%
Feb-16	4,137,546	6,843	29	86.9%
Mar-16	4,519,207	6,417	31	94.7%
Apr-16	3,935,719	6,278	30	87.1%
May-16	4,347,328	8,023	31	72.8%
Jun-16	4,659,290	10,079	30	64.2%
Jul-16	5,145,848	10,748	31	64.4%
Aug-16	4,874,140	10,322	31	63.5%
Sep-16	3,940,207	9,577	30	57.1%
Oct-16	4,226,149	6,615	31	85.9%
Nov-16	4,268,885	6,723	30	88.2%
Dec-16	4,428,820	7,234	31	82.3%
Jan-17	4,418,504	7,068	31	84.0%
Feb-17	4,036,736	6,843	28	87.8%

B.11.4 Monthly Native Energy and Dem-and Requirements – Continued

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Mar-17	4,614,669	6,421	31	96.6%
Apr-17	3,979,999	6,281	30	88.0%
May-17	4,337,876	8,080	31	72.2%
Jun-17	4,711,425	10,176	30	64.3%
Jul-17	5,195,951	10,844	31	64.4%
Aug-17	4,915,160	10,419	31	63.4%
Sep-17	4,142,547	9,738	30	59.1%
Oct-17	4,242,629	6,634	31	86.0%
Nov-17	4,298,799	6,739	30	88.6%
Dec-17	4,481,733	7,258	31	83.0%
Jan-18	4,461,556	7,093	31	84.5%
Feb-18	4,077,170	6,866	29	85.3%
Mar-18	4,661,921	6,435	31	97.4%
Apr-18	4,019,928	6,294	30	88.7%
May-18	4,381,834	8,162	31	72.2%
Jun-18	4,758,261	10,296	30	64.2%
Jul-18	5,247,309	10,965	31	64.3%
Aug-18	4,964,545	10,544	31	63.3%
Sep-18	4,184,445	9,880	30	58.8%
Oct-18	4,286,479	6,639	31	86.8%
Nov-18	4,343,089	6,746	30	89.4%
Dec-18	4,526,006	7,269	31	83.7%
Jan-19	4,505,725	7,106	31	85.2%
Feb-19	4,118,599	6,878	28	89.1%
Mar-19	4,710,351	6,441	31	98.3%
Apr-19	4,060,588	6,299	30	89.5%
May-19	4,426,619	8,232	31	72.3%
Jun-19	4,805,966	10,406	30	64.1%
Jul-19	5,298,921	11,072	31	64.3%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Monthly Native Energy Requirements,

Base Peak Demand and Load Factors

	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Aug-19	5,014,215	10,654	31	63.3%
Sep-19	4,226,640	10,024	30	58.6%
Oct-19	4,329,680	6,645	31	87.6%
Nov-19	4,386,694	6,752	30	90.2%
Dec-19	4,569,540	7,280	31	84.4%
Jan-20	4,553,062	7,119	31	86.0%
Feb-20	4,307,813	6,888	29	89.9%
Mar-20	4,707,143	6,442	31	98.2%
Apr-20	4,096,527	6,298	30	90.3%
May-20	4,528,151	8,299	31	73.3%
Jun-20	4,847,804	10,511	30	64.1%
Jul-20	5,350,687	11,176	31	64.4%
Aug-20	5,071,472	10,762	31	63.3%
Sep-20	4,097,632	10,148	30	56.1%
Oct-20	4,400,552	6,636	31	89.1%
Nov-20	4,444,127	6,744	30	91.5%
Dec-20	4,602,507	7,276	31	85.0%
Jan-21	4,592,238	7,116	31	86.7%
Feb-21	4,199,808	6,884	28	90.8%
Mar-21	4,805,486	6,444	31	100.2%
Apr-21	4,140,610	6,299	30	91.3%
May-21	4,514,813	8,351	31	72.7%
Jun-21	4,899,607	10,600	30	64.2%
Jul-21	5,400,627	11,265	31	64.4%
Aug-21	5,112,194	10,853	31	63.3%

B.11.4 Monthly Native Energy and Demand Requirements – Continued

NSPM 2007 Resource Plan

Xcel Energy
NSP Electric - Total System
Certificate of Need Filing
Median Forecast (50th Percentile)
With 1.1% of Retail Sales DSM Adjustment

Monthly Native Energy Requirements,
Base Peak Demand and Load Factors

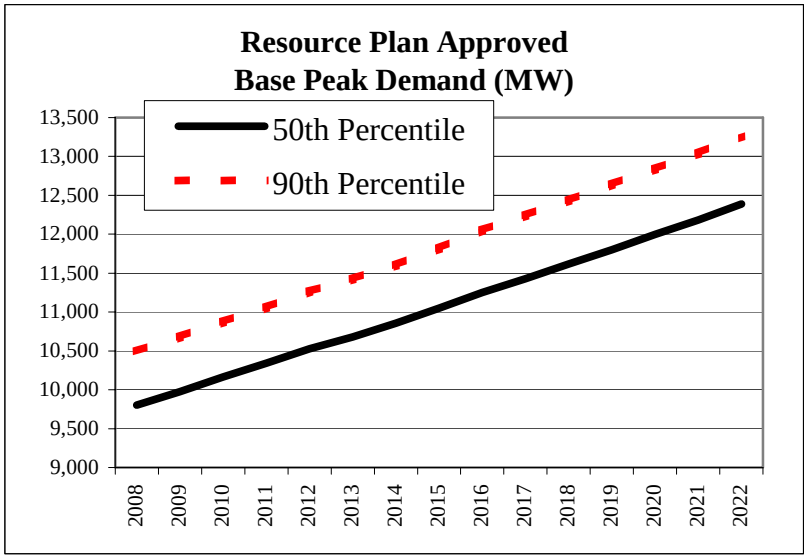
	Native Energy Requirements (MWh)	Base Peak Demand (MW)	Days	Load Factor
Sep-21	4,310,080	10,304	30	58.1%
Oct-21	4,415,732	6,653	31	89.2%
Nov-21	4,473,474	6,758	30	91.9%
Dec-21	4,656,020	7,297	31	85.8%
Jan-22	4,635,631	7,138	31	87.3%
Feb-22	4,240,539	6,905	28	91.4%
Mar-22	4,853,257	6,455	31	101.1%
Apr-22	4,181,011	6,308	30	92.1%
May-22	4,559,366	8,429	31	72.7%
Jun-22	4,946,900	10,716	30	64.1%
Jul-22	5,452,114	11,379	31	64.4%
Aug-22	5,161,820	10,972	31	63.2%
Sep-22	4,352,362	10,440	30	57.9%
Oct-22	4,459,383	6,655	31	90.1%
Nov-22	4,517,483	6,762	30	92.8%
Dec-22	4,699,828	7,305	31	86.5%

B.12 FORECAST COMPARISONS

NSP Total System Base Peak Demand (MW) and Net Energy Requirements (MWh)

NSP Resource Plan Comments, Developed February– March 2005

	50th percentile Annual Base Peak Demand (Mw)	90th percentile Annual Base Peak Demand (Mw)	50th percentile Annual Net Energy Requirements (Mwh)
2008	9,802	10,496	48,428,121
2009	9,975	10,679	49,042,914
2010	10,165	10,874	49,839,238
2011	10,341	11,058	50,585,761
2012	10,528	11,266	51,450,923
2013	10,682	11,425	52,066,570
2014	10,857	11,601	52,856,413
2015	11,049	11,818	53,678,550
2016	11,254	12,050	54,646,114
2017	11,431	12,239	55,358,388
2018	11,617	12,435	56,210,883
2019	11,801	12,638	57,072,089
2022	11,997	12,838	58,096,397
2021	12,183	13,039	58,879,521
2022	12,387	13,260	59,839,229
Compound Growth Rate 2008-2022	**1.7%**	**1.7%**	**1.5%**

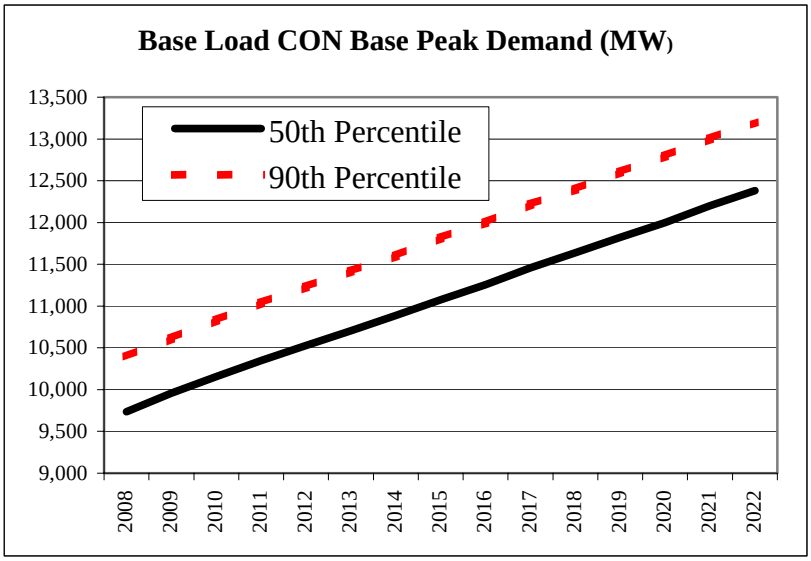


B.12 FORECAST COMPARISONS – Continued

NSP Total System Base Peak Demand (MW) and Net Energy Requirements (MWh)

Base Load CON, Developed September 2006

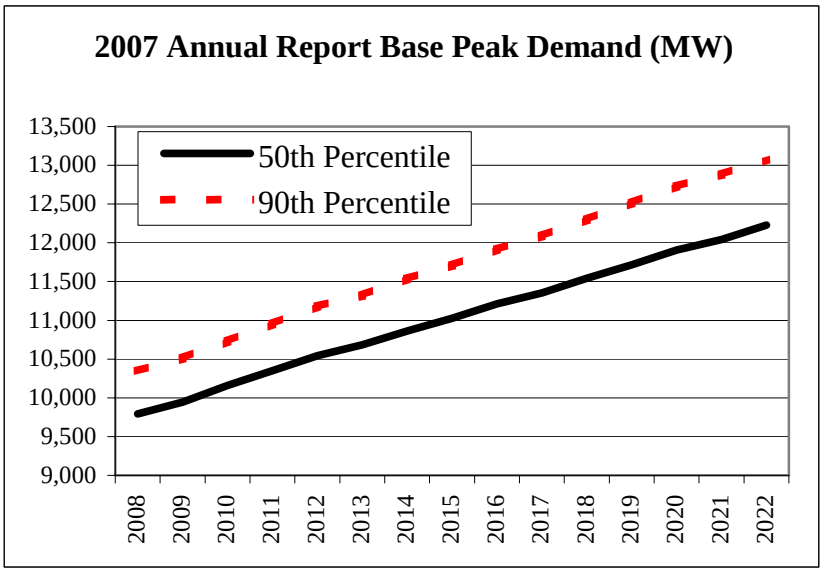
	50th percentile Annual Base Peak Demand (Mw)	90th percentile Annual Base Peak Demand (Mw)	50th percentile Annual Net Energy Requirements (Mwh)
2008	9,737	10,394	48,884,398
2009	9,959	10,611	49,811,120
2010	10,156	10,832	50,705,794
2011	10,348	11,038	51,625,282
2012	10,528	11,228	52,444,045
2013	10,706	11,418	53,352,100
2014	10,887	11,602	54,285,466
2015	11,076	11,816	55,244,670
2016	11,257	11,999	56,169,194
02017	11,460	12,217	57,126,151
2018	11,639	12,397	58,092,539
2019	11,824	12,602	59,065,704
2022	11,997	12,795	60,039,946
2021	12,201	13,003	61,041,701
2022	12,382	13,202	62,099,223
Compound Growth Rate: 2008-2022	**1.7%**	**1.7%**	**1.7%**



B.12 FORECAST COMPARISONS – Continued

NSP Total System Base Peak Demand (MW) and Net Energy Requirements (MWh)

2007 Electric Utility Annual Report, Developed March– May 2007			
	50th percentile Annual Base Peak Demand (MW)	90th percentile Annual Base Peak Demand (MW)	50th percentile Annual Net Energy Requirements (MWh)
2008	9,794	10,346	48,299,200
2009	9,947	10,509	48,829,622
2010	10,159	10,732	49,537,523
2011	10,350	10,952	50,169,349
2012	10,543	11,180	50,752,962
2013	10,684	11,319	51,310,171
2014	10,862	11,533	51,857,925
2015	11,027	11,708	52,419,640
2016	11,212	11,913	53,012,928
2017	11,353	12,087	53,629,066
2018	11,543	12,299	54,277,413
2019	11,718	12,513	54,923,440
2022	11,906	12,727	55,564,816
2021	12,042	12,879	56,174,843
2022	12,227	13,075	56,811,606
Compound Growth Rate: 2008 - 2022	**1.6%**	**1.7%**	**1.2%**

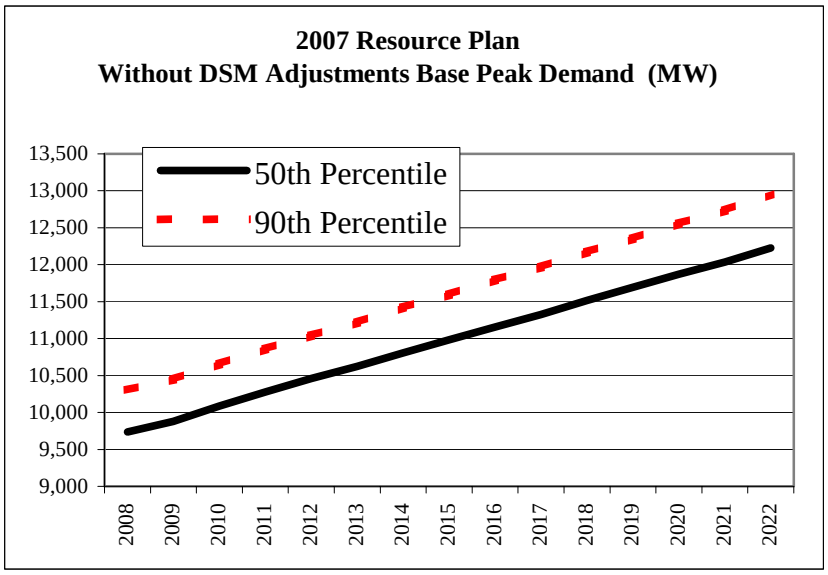


B.12 FORECAST COMPARISONS – Continued

NSP Total System Base Peak Demand (MW) and Net Energy Requirements (MWh)

2007 Resource Plan Forecast, Developed October–November (Without DSM Adjustments)

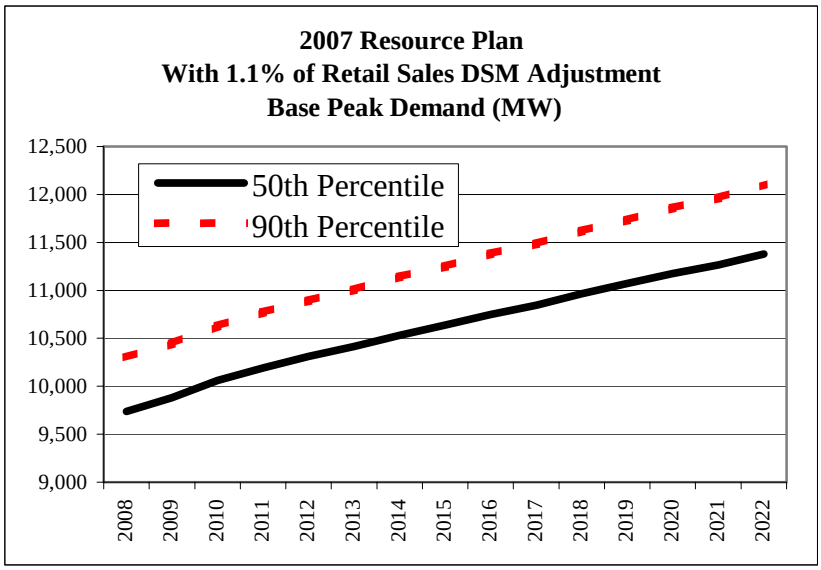
	50th percentile Annual Base Peak Demand (MW)	90th percentile Annual Base Peak Demand (MW)	50th percentile Annual Net Energy Requirements (MWh)
2008	9,737	10,302	48,373,213
2009	9,881	10,446	48,882,025
2010	10,087	10,656	49,644,192
2011	10,277	10,859	50,326,684
2012	10,459	11,042	50,998,180
2013	10,626	11,218	51,601,327
2014	10,808	11,420	52,204,471
2015	10,982	11,593	52,827,006
2016	11,158	11,793	53,475,257
2017	11,324	11,966	54,093,871
2018	11,515	12,169	54,739,404
2019	11,694	12,354	55,393,752
2022	11,871	12,555	56,065,456
2021	12,035	12,732	56,700,893
2022	12,226	12,952	57,366,641
Compound Growth Rate: 2008-2022	**1.6%**	**1.6%**	**1.2%**



B.12 FORECAST COMPARISONS – Continued

NSP Total System Base Peak Demand (MW) and Net Energy Requirements (MWh)

2007 Resource Plan Forecast, Developed October-November 2007 (Contains 1.0% of Retail Sales DSM Adjustment)			
	50th percentile Annual Base Peak Demand (MW)	90th percentile Annual Base Peak Demand (MW)	50th percentile Annual Net Energy Requirements (MWh)
2008	9,737	10,302	48,373,213
2009	9,881	10,446	48,882,025
2010	10,060	10,630	49,573,779
2011	10,190	10,773	50,177,296
2012	10,310	10,893	50,764,710
2013	10,414	11,006	51,279,128
2014	10,531	11,143	51,789,318
2015	10,639	11,250	52,314,897
2016	10,748	11,382	52,862,291
2017	10,844	11,487	53,376,029
2018	10,965	11,619	53,912,542
2019	11,072	11,732	54,453,539
2022	11,176	11,860	55,007,477
2021	11,265	11,961	55,520,687
2022	11,379	12,105	56,059,694
Compound Growth Rate: 2008-2002	**1.1%**	**1.2%**	**1.1%**



B.13 SYSTEM CAPACITY INFORMATION

Table B.13.1

Seasonal Firm Purchases – SUMMER
(MN Rules 7849.0280, Item B)

		Nebraska Public Power District	Mid America Energy	Minnesota Power	Dairyland	Iowa Illinois Gas and Elec.	Union Elec.	Enron Power Marketing, Inc.	Omaha Public Power District	MidAmerican Energy Corp.	Trans Alta	Central MN Municipal Power Coop	Basin Electric Power Compnay	Great River Energy	Western Area Power Administration	Manitoba 150	Manitoba 200	Total
1996	SUMMER			150	4					100						150	200	604
1997	SUMMER			150	4											150	200	504
1998	SUMMER	60		225	4			65	44	50						150	200	798
1999	SUMMER		50	175	4			30	56							150	200	665
2000	SUMMER			250				150			25					150	200	775
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		200	202
2016	SUMMER														2		200	202
2017	SUMMER														2			2
2018	SUMMER														2			2
2019	SUMMER														2			2
2020	SUMMER														2			2
2021	SUMMER														2			2
2022	SUMMER														2			2

Table B.13.2

Seasonal Firm Purchases – WINTER
(MN Rules 7849.0280, Item B)

		Dairyland	MidAmerican Energy Corp	Minnesota Power	Manitoba Hydro	Central MN Municipal Power Agency	Basin Elec. Power Corp	Great River Energy	Western Area Power Administration	Total
1996	WINTER	4								4
1997	WINTER	4								4
1998	WINTER	4								4
1999	WINTER	4								4
2000	WINTER		200	25	50					275
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								2	2
2022	WINTER								2	2

Table B.13.3

Seasonal Firm Sales – SUMMER
(MN Rules 7849.0280, Item B)

		Wisconsin Public Service	Enron	Municipals	United Power	Wisconsin Rapids	Power Co.	Barron	Enron Power Marketing, Inc.	New Ulm	Total
1996	SUMMER	100	45	19		15	100				279
1997	SUMMER			13		15	150				178
1998	SUMMER			14		15		7			36
1999	SUMMER			16	100	15		6			137
2000	SUMMER			13		15		8	150	15	201
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

Table B.13.4

Seasonal Firm Sales – WINTER
(MN Rules 7849.0280, Item B)

		Municipals	United Power	Wisconsin Rapids	Power Co.	Central MN Municipal Power Agency	Barron	Willmar	Manitoba 150	Manitoba 200	Total
1996	WINTER	20	100						150		270
1997	WINTER	18		15	100				150	200	483
1998	WINTER	16	75	15		7		10	150	200	473
1999	WINTER	18		15			6		150	200	389
2000	WINTER	18		15			6		150	200	389
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								400	200	600
2016	WINTER								400		400
2017	WINTER								400		400
2018	WINTER								200		200
2019	WINTER										0
2020	WINTER										0
2021	WINTER										0
2022	WINTER										0

Table B.13.5

Seasonal Participation Purchases - SUMMER
(MN Rules 7849.0280, Item C)

		Ameren Energy Marketing Corp	Barron	Basin Electric Power Coop	Black Hills Power and Light	Calpine	Calpine Mankato	Central Iowa Power Coop	Central MN Municipal Power Agency	Constellation Commodities Group	Coyote	Cyprus	Detroit Edison
1996	SUMMER	0	4								150		
1997	SUMMER	0	4								150		
1998	SUMMER	0	4								150		
1999	SUMMER	150	4	50					5		150		
2000	SUMMER	218	4						2		150		
2001	SUMMER	148						25			150		
2002	SUMMER	235			40						100		
2003	SUMMER	255							25		100		
2004	SUMMER	235							25		100		
2005	SUMMER	0							25	100	100		
2006	SUMMER	0				20	320			62	100	40	69
2007	SUMMER	100					312			285	100	40	
2008	SUMMER						312			90	100	40	
2009	SUMMER						312			95	100	40	
2010	SUMMER						312			100	100	40	
2011	SUMMER						312				100		
2012	SUMMER						312				100		
2013	SUMMER						312				100		
2014	SUMMER						312				100		
2015	SUMMER						312				100		
2016	SUMMER						312				0		
2017	SUMMER						312				0		
2018	SUMMER						312				0		
2019	SUMMER						312				0		
2020	SUMMER						312				0		
2021	SUMMER						312				0		
2022	SUMMER						312				0		

Table B.13.5 - Continued

Seasonal Participation Purchases – SUMMER
(MN Rules 7849.0280, Item C)

		Dynegy Power Marketing	Dynegy Power Marketing	Enron Power Marketing	Exelon	Fibro Minn	Gen Sys Energy	Generic PPA	Great River Energy	Hutchinson Utilities Commission	Invenergy	Kansas City Power and Light	Laurentian	LS Power	Madelia	Manitoba Hydro	Manitoba Hydro Baseload
1996	SUMMER															750	
1997	SUMMER											50				500	
1998	SUMMER											50			8	500	
1999	SUMMER														8	725	
2000	SUMMER			100											8	675	
2001	SUMMER		100	100											8	700	
2002	SUMMER		150				20			6		25				600	
2003	SUMMER		100													760	
2004	SUMMER		100				50									960	
2005	SUMMER		158				70									700	
2006	SUMMER	108	300		125	0		0			0		0	245		713	
2007	SUMMER	108	550			50		0	160	20	0		35	245		500	
2008	SUMMER	108	150			50		0			301		35	245		713	
2009	SUMMER					50		0			301		35	245		713	
2010	SUMMER					50		136			301		35	245		500	
2011	SUMMER					50		136			301		35	245		500	
2012	SUMMER					50		136			301		35	245		500	
2013	SUMMER					50		349			301		35	245		500	
2014	SUMMER					50		485			301		35	245		500	
2015	SUMMER					50		485			301		35	245			375
2016	SUMMER					50		969			301		35	245			375
2017	SUMMER					50		1241			301		35	245			375
2018	SUMMER					50		1649			301		35	245			375
2019	SUMMER					50		1921			301		35	245			375
2020	SUMMER					50		2057			301		35	245			375
2021	SUMMER					50		2193			301		35	245			375
2022	SUMMER					50		2193			301		35	245			375

Table B.13.5 - Continued

Seasonal Participation Purchases – SUMMER
(MN Rules 7849.0280, Item C)

		MidAmerican Energy Corp	Minnesota Power	Minnkota Power Coop	Basin Municipal Power	MN Municipal Power Agency	Montana Dakota Utilties	MPEX (a division of MP)	Non-Utility Group	Indiana Public Service Co	Public Power District	Otter Tail Power	Reliant Energy Services
1996	SUMMER			150					110			75	
1997	SUMMER	50		50					328			75	
1998	SUMMER			50	10				356			75	
1999	SUMMER			50			10		360		40	75	
2000	SUMMER			50					360			75	
2001	SUMMER			20				15	365	50		75	50
2002	SUMMER	150	50	20					364			75	
2003	SUMMER	150	100	0					381		10	75	
2004	SUMMER	150	100	0					381			75	
2005	SUMMER		100	0		130			381			50	
2006	SUMMER		100	100					75				
2007	SUMMER		100	100		10			75				
2008	SUMMER			100		10			75				
2009	SUMMER			100		10			75				
2010	SUMMER			100		10			75				
2011	SUMMER			100					75				
2012	SUMMER			100					75				
2013	SUMMER			100					71				
2014	SUMMER			100					71				
2015	SUMMER			100					71				
2016	SUMMER								71				
2017	SUMMER								71				
2018	SUMMER								38				
2019	SUMMER								38				
2020	SUMMER								38				
2021	SUMMER								38				
2022	SUMMER								38				

Table B.13.5 - Continued

Seasonal Participation Purchases – SUMMER
(MN Rules 7849.0280, Item C)

		Short Term	Split Rock Energy	St. Paul	The Energy Authority	United Power Assoc	Utilicorp United	Utilicorp United	Western Resources Inc.	Wind	Wisconsin Electric Power	Wisconsin Public Service	**Total**
1996	SUMMER					50						50	1339
1997	SUMMER					50							1257
1998	SUMMER					50					120		1373
1999	SUMMER					50		35	100			73	1885
2000	SUMMER					50			50				1742
2001	SUMMER					50	100		83				2039
2002	SUMMER		50		30	50	50	10					2025
2003	SUMMER				20	50			61				2087
2004	SUMMER		100			50							2326
2005	SUMMER					50						200	2064
2006	SUMMER	0	200	25		50				61		50	2763
2007	SUMMER	0		25		50				76			2941
2008	SUMMER	642		25		50				76			3122
2009	SUMMER	750		25		50				96			2997
2010	SUMMER	750		25						96			2875
2011	SUMMER	750		25						98			2727
2012	SUMMER	750		25						99			2728
2013	SUMMER	750		25						100			2938
2014	SUMMER	750		25						101			3075
2015	SUMMER	750		25						102			2951
2016	SUMMER	750		25						102			3235
2017	SUMMER	750		25						102			3507
2018	SUMMER	750		25						102			3882
2019	SUMMER	750		25						101			4153
2020	SUMMER	750		25						101			4289
2021	SUMMER	750		25						101			4425
2022	SUMMER	750		25						101			4425

Table B.13.6

Seasonal Participation Purchases - WINTER
(MN Rules 7849.0280, Item C)

		American Energy Marketing Corp	Barron	Calpine Mankato	Central MN Municipal Power Agency	Cyprus	Dynegy Power Marketing	Fibro Minn	Generic PPA	Gen Sys Energy	Invenergy	Laurentian	LS Power	Madelia	Manitoba Hydro
1996	WINTER														500
1997	WINTER														500
1998	WINTER														500
1999	WINTER		4												500
2000	WINTER		4											8	500
2001	WINTER	100	4		2		100							8	500
2002	WINTER		4				100								500
2003	WINTER		4		25		100								500
2004	WINTER				25										500
2005	WINTER				25					50					500
2006	WINTER			262	31	40				50	0	0	262		500
2007	WINTER			262		40	108	50			0	35	262		713
2008	WINTER			262		40		50			357	35	262		713
2009	WINTER			262		40		50			357	35	262		500
2010	WINTER			262		40		50	160		357	35	262		500
2011	WINTER			262				50	160		357	35	262		500
2012	WINTER			262				50	160		357	35	262		500
2013	WINTER			262				50	410		357	35	262		500
2014	WINTER			262				50	570		357	35	262		500
2015	WINTER			262				50	570		357	35	262		
2016	WINTER			262				50	1140		357	35	262		
2017	WINTER			262				50	1460		357	35	262		
2018	WINTER			262				50	1940		357	35	262		
2019	WINTER			262				50	2260		357	35	262		
2020	WINTER			262				50	2420		357	35	262		
2021	WINTER			262				50	2580		357	35	262		
2022	WINTER			262				50	2580		357	35	262		

Table B.13.6 - Continued

Seasonal Participation Purchases – WINTER
(MN Rules 7849.0280, Item C)

		Manitoba Hydro Baseload	MidAmerican Energy Corp	Minnesota Power	Minnkota Power Coop	Non-Utility Group	St. Paul	Western Resources Inc.	Wind	Wisconsin Public Service	**Total**
1996	WINTER					98				150	748
1997	WINTER					111				150	761
1998	WINTER					374				150	1,024
1999	WINTER					375					879
2000	WINTER					377					889
2001	WINTER					377					1,091
2002	WINTER			50		373		61			1,088
2003	WINTER		50		20	377					1,076
2004	WINTER			100		398					1,023
2005	WINTER			100		398					1,073
2006	WINTER			100		75	25		145	87	1,577
2007	WINTER			100		75	25		148		1,818
2008	WINTER					75	25		152		1,971
2009	WINTER					75	25		152		1,758
2010	WINTER					75	25		173		1,939
2011	WINTER					75	25		184		1,910
2012	WINTER					75	25		206		1,931
2013	WINTER					71	25		216		2,188
2014	WINTER					71	25		227		2,360
2015	WINTER	375				71	25		227		2,235
2016	WINTER	375				71	25		227		2,805
2017	WINTER	375				71	25		225		3,123
2018	WINTER	375				38	25		219		3,563
2019	WINTER	375				38	25		219		3,882
2020	WINTER	375				38	25		219		4,042
2021	WINTER	375				38	25		219		4,203
2022	WINTER	375				38	25		219		4,203

Table B.13.7

Seasonal Participation Sales – SUMMER
(MN Rules 7849.0280, Item C)

		Constellation Comm. Group	Gensys Energy	Great River Energy	Melrose	Montana Dakota Util	Montana Dakota Util	Omaha Public Power District	Otter Tail Power	Wisc Power Assoc	Wisconsin Electric Power Corp	Wisconsin Public Service	**Total**
1996	SUMMER									150			150
1997	SUMMER												0
1998	SUMMER				3					126	250		379
1999	SUMMER				3			50			250	176	479
2000	SUMMER				3				50			186	239
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

Table B.13.8

Seasonal Participation Sales – WINTER
(MN Rules 7849.0280, Item C)

		Melrose	Minnkota Power	Municipals	Otter Tail Power	United Power Assoc	Wisc Power Assoc	Wisconsin Electric Power Corp	**Total**
1996	WINTER		50		75	50	150		325
1997	WINTER		50		75	50	150		325
1998	WINTER	3	50		75	50	150		328
1999	WINTER	3	50		75	50	150		328
2000	WINTER	3	50		75	50		150	328
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								0
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

Table B.13.9

Load and Generating Capacity Data Excluding Plants Needing a CON - SUMMER (MN Rules 7849.0280, Item D)

	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
1996	7488	7488	604	279	7163	7163	7110	1339	150	8299	1074	8237	62
1997	7353	7353	504	178	7027	7027	7118	1257	0	8375	1054	8081	294
1998	7659	7659	798	36	6897	6897	7150	1373	379	8144	1035	7932	212
1999	7990	7990	665	137	7462	7462	7187	1885	479	8593	1119	8581	12
2000	7936	7936	775	201	7362	7362	7243	1742	239	8746	1104	8466	280
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	2763	82	10308	1282	9829	479
2007	9427	9427	352	0	9075	9075	7577	2941	345	10172	1361	10436	-264
2008	10302	10302	352	0	9950	9950	7432	3122	250	10304	1493	11443	-1139
2009	10446	10446	352	0	10094	10094	7970	2997	105	10862	1514	11608	-746
2010	10630	10630	352	0	10278	10278	8033	2875	110	10798	1542	11819	-1021
2011	10773	10773	352	0	10421	10421	8085	2727	0	10812	1563	11984	-1172
2012	10893	10893	352	0	10541	10541	8097	2728	0	10825	1581	12122	-1297
2013	11006	11006	352	0	10654	10654	8097	2938	0	11035	1598	12252	-1217
2014	11143	11143	352	0	10791	10791	8097	3075	0	11172	1619	12410	-1238
2015	11250	11250	202	0	11048	11048	8097	2951	0	11048	1657	12705	-1658
2016	11382	11382	202	0	11180	11180	8097	3235	0	11332	1677	12857	-1525
2017	11487	11487	2	0	11484	11484	8097	3507	0	11604	1723	13207	-1603
2018	11619	11619	2	0	11617	11617	8097	3882	0	11979	1743	13359	-1381
2019	11732	11732	2	0	11730	11730	8097	4153	0	12250	1760	13490	-1240
2020	11860	11860	2	0	11858	11858	8097	4289	0	12386	1779	13636	-1251
2021	11961	11961	2	0	11959	11959	8097	4425	0	12522	1794	13753	-1232
2022	12105	12105	2	0	12103	12103	8097	4425	0	12522	1815	13919	-1397

Table B.13.9

Load and Generating Capacity Data Excluding Plants Needing a CON – SUMMER - Continued
(MN Rules 7849.0280, Item D)

NOTES :

1. Forecasted demand values based on a 90% forecast level with 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 at nameplate capacity. New wind resources are projected to be accredited at 13.5% nameplate capacity. Actual winter accreditation is likely to be higher.

Table B.13.10

Load and Generating Capacity Data Excluding Plants Needing a CON - WINTER (MN Rules 7849.0280, Item D)

	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
1996	6081	7488	4	270	6347	7754	7253	748	325	7676	1163	7510	166
1997	5869	7353	4	483	6348	7832	7367	761	325	7803	1175	7523	280
1998	5877	7659	4	473	6346	8128	7406	1024	328	8102	1219	7565	537
1999	6187	7990	4	389	6572	8375	7482	879	328	8033	1256	7828	205
2000	6422	7936	275	389	6536	8050	7537	889	328	8098	1208	7744	354
2001	6557	8349	136	384	6805	8597	7534	1091	178	8446	1290	8095	352
2002	6221	8239	139	362	6444	8462	7491	1088	135	8444	1269	7713	731
2003	6386	8281	2	365	6749	8644	7738	1076	125	8689	1297	8045	643
2004	6653	8596	127	365	6891	8834	7718	1023	128	8613	1325	8216	397
2005	6873	8501	127	366	7112	8740	7718	1073	53	8738	1311	8423	315
2006	6833	9034	131	365	7067	9268	7936	1577	50	9463	1390	8457	1006
2007	7413	9427	2	350	7760	9775	7616	1818	50	9384	1466	9227	157
2008	7509	10302	2	350	7856	10650	7895	1971	50	9815	1598	9454	361
2009	7575	10446	2	350	7923	10793	8401	1758	50	10108	1619	9542	566
2010	7646	10630	2	350	7994	10977	8464	1939	0	10403	1647	9640	763
2011	7664	10773	2	350	8011	11120	8516	1910	0	10426	1668	9679	747
2012	7676	10893	2	350	8024	11241	8528	1931	0	10460	1686	9710	750
2013	7712	11006	2	350	8060	11354	8528	2188	0	10717	1703	9763	954
2014	7721	11143	2	350	8069	11491	8528	2360	0	10888	1724	9792	1096
2015	7743	11250	2	600	8340	11848	8528	2235	0	10763	1777	10118	645
2016	7747	11382	2	400	8145	11780	8528	2805	0	11333	1767	9912	1421
2017	7777	11487	2	400	8175	11884	8528	3123	0	11651	1783	9957	1694
2018	7790	11619	2	200	7988	11817	8528	3563	0	12091	1772	9760	2330
2019	7815	11732	2	0	7813	11730	8528	3882	0	12411	1760	9572	2838
2020	7810	11860	2	0	7808	11858	8528	4042	0	12571	1779	9587	2984
2021	7839	11961	2	0	7837	11959	8528	4203	0	12731	1794	9631	3100
2022	7853	12105	2	0	7851	12103	8528	4203	0	12731	1816	9667	3064

Table B.13.10 - Continued

Load and Generating Capacity Data Excluding Plants Needing a CON - WINTER
(MN Rules 7849.0280, Item D)

NOTES :
1. Forecasted demand values based on a 90% 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 at nameplate capacity. New wind resources are projected to be accredited at 13.5% nameplate capacity. Actual winter accreditation is likely to be higher.

Table B.13.11

Load and Generating Capacity Data Including Plants Needing a CON - SUMMER (MN Rules 7849.0280, Item E)

	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
1996	7488	7488	604	279	7163	7163	7110	1339	150	8299	1074	8237	62
1997	7353	7353	504	178	7027	7027	7118	1257	0	8375	1054	8081	294
1998	7659	7659	798	36	6897	6897	7150	1373	379	8144	1035	7932	212
1999	7990	7990	665	137	7462	7462	7187	1885	479	8593	1119	8581	12
2000	7936	7936	775	201	7362	7362	7243	1742	239	8746	1104	8466	280
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	2763	82	10308	1282	9829	479
2007	9427	9427	352	0	9075	9075	7577	2941	345	10172	1361	10436	-264
2008	10302	10302	352	0	9950	9950	7432	3122	250	10304	1493	11443	-1139
2009	10446	10446	352	0	10094	10094	7985	2997	105	10877	1514	11608	-731
2010	10630	10630	352	0	10278	10278	8048	2875	110	10813	1542	11819	-1006
2011	10773	10773	352	0	10421	10421	8156	2727	0	10883	1563	11984	-1101
2012	10893	10893	352	0	10541	10541	8168	2728	0	10896	1581	12122	-1227
2013	11006	11006	352	0	10654	10654	8168	2938	0	11105	1598	12252	-1147
2014	11143	11143	352	0	10791	10791	8168	3075	0	11242	1619	12410	-1168
2015	11250	11250	202	0	11048	11048	8168	2951	0	11118	1657	12705	-1587
2016	11382	11382	202	0	11180	11180	8168	3235	0	11403	1677	12857	-1454
2017	11487	11487	2	0	11484	11484	8168	3507	0	11675	1723	13207	-1532
2018	11619	11619	2	0	11617	11617	8168	3882	0	12049	1743	13359	-1310
2019	11732	11732	2	0	11730	11730	8168	4153	0	12320	1760	13490	-1169
2020	11860	11860	2	0	11858	11858	8168	4289	0	12456	1779	13636	-1180
2021	11961	11961	2	0	11959	11959	8168	4425	0	12592	1794	13753	-1161
2022	12105	12105	2	0	12103	12103	8168	4425	0	12592	1815	13919	-1327

Table B.13.11 - Continued

Load and Generating Capacity Data Including Plants Needing a CON - SUMMER
(MN Rules 7849.0280, Item E)

NOTES :
1. Forecasted demand values based on a 90% 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 at nameplate capacity. New wind resources are projected to be accredited at 13.5% nameplate capacity.
4. Monticello power uprate of 71 MW added to net generating capacity.

Table B.13.12

Load and Generating Capacity Data Including Plants Needing a CON - WINTER (MN Rules 7849.0280, Item E)

	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
1996	6081	7488	4	270	6347	7754	7253	748	325	7676	1163	7510	166
1997	5869	7353	4	483	6348	7832	7367	761	325	7803	1175	7523	280
1998	5877	7659	4	473	6346	8128	7406	1024	328	8102	1219	7565	537
1999	6187	7990	4	389	6572	8375	7482	879	328	8033	1256	7828	205
2000	6422	7936	275	389	6536	8050	7537	889	328	8098	1208	7744	354
2001	6557	8349	136	384	6805	8597	7534	1091	178	8446	1290	8095	352
2002	6221	8239	139	362	6444	8462	7491	1088	135	8444	1269	7713	731
2003	6386	8281	2	365	6749	8644	7738	1076	125	8689	1297	8045	643
2004	6653	8596	127	365	6891	8834	7718	1023	128	8613	1325	8216	397
2005	6873	8501	127	366	7112	8740	7718	1073	53	8738	1311	8423	315
2006	6833	9034	131	365	7067	9268	7936	1577	50	9463	1390	8457	1006
2007	7413	9427	2	350	7760	9775	7616	1818	50	9384	1466	9227	157
2008	7509	10302	2	350	7856	10650	7895	1971	50	9815	1598	9454	361
2009	7575	10446	2	350	7923	10793	8416	1758	50	10108	1619	9542	566
2010	7646	10630	2	350	7994	10977	8479	1939	0	10403	1647	9640	763
2011	7664	10773	2	350	8011	11120	8599	1910	0	10426	1668	9679	747
2012	7676	10893	2	350	8024	11241	8599	1931	0	10460	1686	9710	750
2013	7712	11006	2	350	8060	11354	8599	2188	0	10717	1703	9763	954
2014	7721	11143	2	350	8069	11491	8599	2360	0	10888	1724	9792	1096
2015	7743	11250	2	600	8340	11848	8599	2235	0	10763	1777	10118	645
2016	7747	11382	2	400	8145	11780	8599	2805	0	11333	1767	9912	1421
2017	7777	11487	2	400	8175	11884	8599	3123	0	11651	1783	9957	1694
2018	7790	11619	2	200	7988	11817	8599	3563	0	12091	1772	9760	2330
2019	7815	11732	2	0	7813	11730	8599	3882	0	12411	1760	9572	2838
2020	7810	11860	2	0	7808	11858	8599	4042	0	12571	1779	9587	2984
2021	7839	11961	2	0	7837	11959	8599	4203	0	12731	1794	9631	3100
2022	7853	12105	2	0	7851	12103	8599	4203	0	12731	1816	9667	3064

Table B.13.12 - Continued

Load and Generating Capacity Data Including Plants Needing a CON - WINTER
(MN Rules 7849.0280, Item E)

NOTES :
1. Forecasted demand values based on a 90% 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 at nameplate capacity. New wind resources are projected to be accredited at 13.5% nameplate capacity. Actual winter accreditation is likely to be higher.
4. Monticello power uprate of 71 MW added to net generating capacity.

Table B.13.13

Load and Generating Capacity Data Including Future Plants Needing a CON - SUMMER (MN Rules 7849.0280, Item F)

	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
1996	7488	7488	604	279	7163	7163	7110	1339	150	8299	1074	8237	62
1997	7353	7353	504	178	7027	7027	7118	1257	0	8375	1054	8081	294
1998	7659	7659	798	36	6897	6897	7150	1373	379	8144	1035	7932	212
1999	7990	7990	665	137	7462	7462	7187	1885	479	8593	1119	8581	12
2000	7936	7936	775	201	7362	7362	7243	1742	239	8746	1104	8466	280
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	2763	82	10308	1282	9829	479
2007	9427	9427	352	0	9075	9075	7577	2941	345	10172	1361	10436	-264
2008	10302	10302	352	0	9950	9950	7432	3122	250	10304	1493	11443	-1139
2009	10446	10446	352	0	10094	10094	7984	2997	105	10877	1514	11608	-731
2010	10630	10630	352	0	10278	10278	8048	2875	110	10813	1542	11819	-1006
2011	10773	10773	352	0	10421	10421	8156	2727	0	10883	1563	11984	-1101
2012	10893	10893	352	0	10541	10541	8168	2728	0	10896	1581	12122	-1227
2013	11006	11006	352	0	10654	10654	8250	2938	0	11188	1598	12252	-1064
2014	11143	11143	352	0	10791	10791	8250	3075	0	11325	1619	12410	-1085
2015	11250	11250	202	0	11048	11048	8337	2951	0	11288	1657	12705	-1417
2016	11382	11382	202	0	11180	11180	8337	3235	0	11573	1677	12857	-1285
2017	11487	11487	2	0	11484	11484	8337	3507	0	11845	1723	13207	-1363
2018	11619	11619	2	0	11617	11617	8337	3882	0	12219	1743	13359	-1140
2019	11732	11732	2	0	11730	11730	8337	4153	0	12490	1760	13490	-1000
2020	11860	11860	2	0	11858	11858	8337	4289	0	12626	1779	13636	-1010
2021	11961	11961	2	0	11959	11959	8337	4425	0	12762	1794	13753	-991
2022	12105	12105	2	0	12103	12103	8337	4425	0	12762	1815	13919	-1157

Table B.13.13 - Continued

Load and Generating Capacity Data Including Future Plants Needing a CON - SUMMER
(MN Rules 7849.0280, Item F)

NOTES :
1. Forecasted demand values based on a 90% 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 at nameplate 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.
Xcel Energy has issued an RFP for a 160 MW of Summer peaking to be available by 2011. We are still in the selection process and no term sheet has been signed to date.
Since this will result in a Summer only PPA a CON is not required.
5. Xcel Energy will need additional resources in future years, the specific details will be addressed in future resource plans.

Table B.13.14

Load and Generating Capacity Data Including Future Plants Needing a CON - WINTER (MN Rules 7849.0280, Item F)

	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
1996	6081	7488	4	270	6347	7754	7253	748	325	7676	1163	7510	166
1997	5869	7353	4	483	6348	7832	7367	761	325	7803	1175	7523	280
1998	5877	7659	4	473	6346	8128	7406	1024	328	8102	1219	7565	537
1999	6187	7990	4	389	6572	8375	7482	879	328	8033	1256	7828	205
2000	6422	7936	275	389	6536	8050	7537	889	328	8098	1208	7744	354
2001	6557	8349	136	384	6805	8597	7534	1091	178	8446	1290	8095	352
2002	6221	8239	139	362	6444	8462	7491	1088	135	8444	1269	7713	731
2003	6386	8281	2	365	6749	8644	7738	1076	125	8689	1297	8045	643
2004	6653	8596	127	365	6891	8834	7718	1023	128	8613	1325	8216	397
2005	6873	8501	127	366	7112	8740	7718	1073	53	8738	1311	8423	315
2006	6833	9034	131	365	7067	9268	7936	1577	50	9463	1390	8457	1006
2007	7413	9427	2	350	7760	9775	7616	1818	50	9384	1466	9227	157
2008	7509	10302	2	350	7856	10650	7895	1971	50	9815	1598	9454	361
2009	7575	10446	2	350	7923	10793	8401	1758	50	10108	1619	9542	566
2010	7646	10630	2	350	7994	10977	8464	1939	0	10403	1647	9640	763
2011	7664	10773	2	350	8011	11120	8516	1910	0	10426	1668	9679	747
2012	7676	10893	2	350	8024	11241	8528	1931	0	10460	1686	9710	750
2013	7712	11006	2	350	8060	11354	8528	2188	0	10717	1703	9763	954
2014	7721	11143	2	350	8069	11491	8528	2360	0	10888	1724	9792	1096
2015	7743	11250	2	600	8340	11848	8528	2235	0	10763	1777	10118	645
2016	7747	11382	2	400	8145	11780	8528	2805	0	11333	1767	9912	1421
2017	7777	11487	2	400	8175	11884	8528	3123	0	11651	1783	9957	1694
2018	7790	11619	2	200	7988	11817	8528	3563	0	12091	1772	9760	2330
2019	7815	11732	2	0	7813	11730	8528	3882	0	12411	1760	9572	2838
2020	7810	11860	2	0	7808	11858	8528	4042	0	12571	1779	9587	2984
2021	7839	11961	2	0	7837	11959	8528	4203	0	12731	1794	9631	3100
2022	7853	12105	2	0	7851	12103	8528	4203	0	12731	1816	9667	3064

Table B.13.14 - Continued

Load and Generating Capacity Data Including Future Plants Needing a CON - WINTER
(MN Rules 7849.0280, Item F)

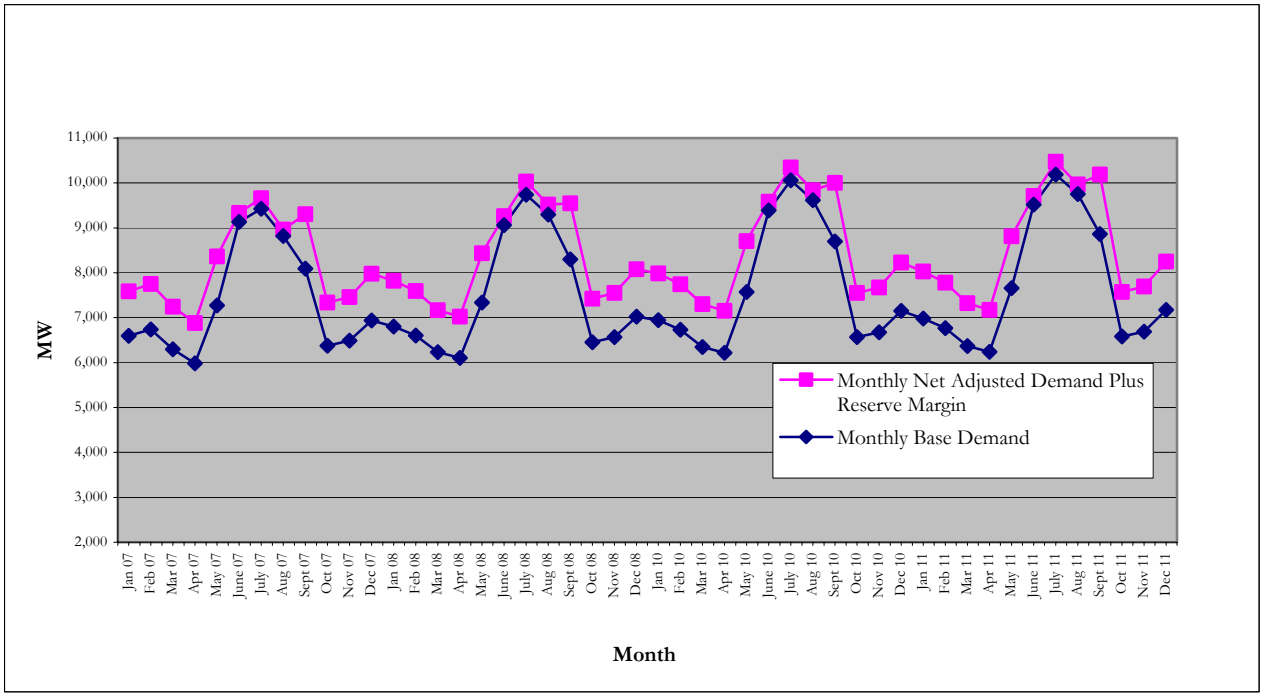
NOTES :
1. Forecasted demand values based on a 90% forecast level with a DSM Adjustment.
2. Summer and winter seasons as defined by MAPP : Summer is May - October, Winter is the following November - April
3. Wind resources are included in net generating capacity at nameplate capacity. The only new wind 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.

Table B.13.15

Proposed Additions and Retirements
(Minnesota Rules 7849.0280, Item G)

	Year	Proposed Additions (MW)	Probable Date of CON Application	Proposed Retirements (MW)	Comments
Projected	2007		Not required	274	High Bridge Coal Retirement
	2008	615	GM Portion only 2007	387	High Bridge CC Addition, Grand Meadow Wind Addition and Riverside Coal Retirement
	2009	454	Not required for Riverside; 2008 for Monticello		Riverside Combined Cycle 439 MW and Monticello 15 MW
	2010				
	2011	56	2008		Monticello uprate 56 MW
	2012	40	Not required		Sherco Upgrades
	2013	123	Not required for Sherco; 2007 for PI		Sherco Upgrades 40 MW and Prairie Island 83 MW
	2014				
	2015	87	2008		Prairie Island uprate 87 MW
	2016				
	2017				
	2018				
	2019				
	2020				
	2021				
	Total	**1,375**		**661**	

Table B.13.16
Monthly Demand and Capability
(Minnesota Rules 7849.0280, Item H)



The Monthly Net Adjusted Demand includes a 1.1% DSM Adjustment, a Load Relief Adjustment, and a 15% Reserve Margin Adjustment.

For the forecasted years, Load Relief is forecasted for June, July and August only.

The Monthly Base Demand includes a 1.1% DSM Adjustment, but no Load Relief and no Reserve Margin.

Appendix C: Demand-Side Management Programs

This Appendix contains the information required in Minn. R. Part 7849.0290 related to demand-side management ("DSM") (conservation and load management) programs.

C.1 Who is Responsible for DSM?

Fred Stoffel, Vice President of Marketing in the Utilities Group, is responsible for Xcel Energy's demand-side management programs in Minnesota, Wisconsin, Colorado, New Mexico, Texas, North Dakota, and South Dakota.

C.2 DSM Goals and Objectives

C.2.1 Current Conservation Goals, 2007-2009

Xcel Energy files a comprehensive conservation plan every three years, which includes proposed budgets and savings goals for the Company's conservation programs. On November 29, 2006, the Department of Commerce (DOC) approved our 2007/2008/2009 CIP Triennial Plan, including the proposed savings goals shown in Table C-1 (Docket No. E,G002/CIP-06-80). DOC staff evaluates energy and demand savings goals by comparing the goals with our Commission-approved integrated Resource Plan goals and historic CIP achievements.

Table C-1
DSM Goals as Approved by the Department in the 2007/2008/2009 CIP Triennial Plan

	2007	2008	2009	Total
Budget	$45,504,799	$47,002,224	$48,350,183	$140,857,206
Generator KW	87,300	90,980	92,809	271,089
Generator kWh	238,213,749	259,635,189	264,114,597	761,963,535

C.2.1.1 The Next Generation Energy Act of 2007

The Next Generation Energy Act of 2007 ("Act") represents a fundamental change in the statutory structure for DSM in Minnesota. The Act sets an aggressive state policy to significantly increase DSM in our energy portfolio and shifts the focus from historical spending to a percentage savings of retail sales. The Act seeks to achieve an annual statewide energy conservation goal of 1.5 percent of retail sales to be achieved through both direct and indirect energy conservation programs. Direct programs are traditional, customer-based Conservation Improvement Programs (CIP). Indirect programs are savings from electric utility infrastructure improvements and waste heat recovery, energy codes, appliance standards, and "market transformation" programs directed at changing consumer behavior and creating lasting market effects. For Xcel Energy, a 1.5 percent savings of retail sales is an effective doubling of the savings set forth in the 2004 Resource Plan.

The statute sets forth that a utility may request that the Commissioner reduce the energy savings required from Conservation Improvement Plans from the 1.5 percent level to a minimum of 1.0 percent of annual retail sales based on certain factors. These factors include historical conservation investment experience, customer class makeup, load growth, a conservation potential study or "other factors the commissioner determines warrants an adjustment." We considered these factors and constraints when determining an achievable goal that will deliver reliable energy savings to help meet the resource needs outlined in our 2007 Resource Plan, filed December 14, 2007.

C.2.1.2 2007 Resource Plan

For our Resource Plan, we proposed a direct energy savings goal equal to 1.1 percent of annual retail sales, assuming a graduated transition to higher DSM goals. Our proposed DSM goal for direct DSM programs will result in over 5,100 GWhs of energy savings and over 1,700 MWs of demand reductions during the 2008 through 2022 planning period. This goal represents a 30 percent increase in energy savings and a 48 percent increase in demand savings over the levels approved by the Commission in our 2004 Resource Plan. This goal is also approximately 35 percent higher than the average GWh savings goals approved in our current CIP Triennial. For perspective, our approved goals in the current CIP Triennial represent approximately 0.8 percent reduction of annual retail sales. Though ambitious, we believe the proposed 1.1 percent goal is achievable, and as a result, we have included this level of energy conservation in the sales forecast and our modeling scenarios.

For comparison purposes, Table C-2 shows our current goals from the 2004 Resource Plan, as Ordered in Docket No E-002-/RP-04-1752, and our proposed 1.1 percent goal for the period 2005 through 2022.

Table C-2
Demand and Energy Goals

Year	2005-2019 Plan	2005-2019 Plan	1.1 percent Scenario	1.1 percent Scenario	1.1 percent Scenario
	Approved Demand Goal MW	Approved Energy Goal GWh	Demand Goal MW	Energy Goal GWh	Proposed Budget
2005	77	266			
2006	79	231			
2007	116	330			
2008	93	294	91	260	$ 47,002,224
2009	84	276	93	264	$ 48,350,183
2010	72	264	119	328	$ 91,535,420
2011	65	251	123	333	$ 95,216,191
2012	69	252	119	338	$ 98,944,600
2013	68	248	118	343	$ 102,656,754
2014	72	253	111	347	$ 106,362,703
2015	73	254	98	351	$ 110,115,550
2016	74	254	104	355	$ 113,957,721
2017	73	256	109	359	$ 117,955,764
2018	72	254	114	363	$ 122,121,965
2019	70	251	116	367	$ 126,482,964
2020			131	372	$ 131,009,189
2021			132	376	$ 135,700,102
2022			134	380	$ 140,550,584
2005-2019 Total	**1,157**	**3,934**			
Avg Annual 2005-2019	**77**	**262**			
2008-2022 Total			**1,711**	**5,136**	
Avg Annual 2008-2022			**114**	**342**	

We have based our goals on information from our current and updated Minnesota DSM Potential Study and historical experience and performance. Our goal through direct DSM programs is a "stretch" plan representing the limits of what our conservation potential study concludes is achievable. Other considerations include internal and external analysis on how our programs can be enhanced and expanded to overcome existing barriers, as well as constraints introduced by the legislation, such as new measurement and verification requirements, changes to codes and standards, and cost effectiveness.

C.2.1.3 2010/2011/2012 Conservation Improvement Plan

The Company's next conservation plan will be filed June 1, 2009, covering the years 2010 through 2012. The plan will reflect the new energy savings goals and provisions of the Next Generation Energy Act of 2007, as well as the goals outlined in the 2007 Resource Plan.

We are currently developing a growth plan to help us meet Minnesota's new energy efficiency requirements. At this stage, we are still working to develop and complete this plan, but we expect most of the energy savings will build upon our most successful business programs such as Cooling, Motors, Lighting and programs that are process driven or more customer service oriented. Our DSM group is currently analyzing every existing program for gaps and opportunities for growth, as well as reviewing new and emerging technologies that may be on the planning horizon, such as certain solar or LED applications. We have also commissioned ACEEE to review our programs and provide recommendations on improvements and enhancements. Additionally, we intend to use available resources to move the market faster through the following:

- Increasing rebate levels,
- Increasing residential customer awareness through consumer education,
- Acquiring additional trained and knowledgeable staff,
- Increasing direct project management, and
- Increasing our service representative levels.

C.2.2 Demand-Side Management Objectives

Xcel Energy has a long-standing commitment to providing cost-effective and high-performing demand-side management programs. We regard conservation, energy efficiency and demand-side management to be one of the most cost-effective resource options available. Providing our customers with a full suite of programs, tools and information to conserve energy helps us meet our customers' growing energy needs and is one of our most significant efforts to reduce environmental impacts.

Our demand-side management objectives in Minnesota are to delay or avoid more expensive electricity generation, reduce pollution and other environmental impacts, and help customers save money by improving the efficiency of their homes and businesses. We consistently exceed the legislative mandate to spend at least two percent of gross electric operating revenues on energy efficiency programs and consistently achieve the conservation levels established in the resource planning process. We look forward to working with the Department and stakeholders to achieve sustainable and reliable energy savings in line with the Act.

We perform continuous assessments of our DSM programs through periodic process evaluations and market potential studies in order to identify new conservation opportunities and strategies to get more savings out of existing programs. We are actively participating in the Department of Commerce's M&V workgroup and are committed to participating in other workgroups as they are initiated.

C.3 Describe the Energy Efficiency Programs Considered, Implemented, and Why Those Considered Were Not Implemented

C.3.1 DSM Programs Consideration

Xcel Energy operates 39 individual electric DSM programs in Minnesota targeted at our Commercial & Industrial, Small Business, Consumer, and Low-Income customer segments. These programs are designed to meet both the minimum-spending requirements of Minn. Stat. § 216B.241, subd. 1(a) and the specific goals established by the Department of Commerce, most recently in Docket No. E,G002/CIP-06-80. Table C.3 below lists the specifics of the programs we currently offer and the corresponding goals for 2007 through 2009.

C.3.2 DSM Programs Implemented

Table C-3
Xcel Energy's 2007-2009 Approved DSM Programs and Goals

2007	Electric Participants	Electric Budget	Customer kW	Generator kW	Generator kWh	Gas Participants	Gas Budget	MCF Savings
Business Segment								
Boiler Efficiency						351	$628,803	238,457
Compressed Air Efficiency	82	$833,676	2,742	2,436	19,001,009			
Computer Efficiency	19,164	$179,154	239	253	2,230,207			
Cooling Efficiency	346	$1,476,190	4,654	3,147	6,748,638			
Custom Efficiency	136	$3,896,676	7,554	6,147	41,030,028	39	$866,073	310,000
Energy Design Assistance	48	$5,549,231	9,396	9,276	39,999,971	11	$159,696	15,004
Energy Management Systems	67	$745,720	1,473	25	13,073,147	13	$47,567	5,122
Furnace Efficiency						132	$49,768	3,589
Industrial Efficiency	4	$1,582,234	803	753	4,462,979	1	$70,498	6,900
Lighting Efficiency	672	$3,534,186	8,721	7,849	40,325,769			
Motor Efficiency	450	$1,717,335	4,518	3,196	25,216,289			
Recommissioning	96	$1,172,021	1,821	867	11,878,383	35	$66,870	9,000
Segment Efficiency	218	$1,612,054	507	323	2,639,195	85	$58,372	3,599
Conservation Subtotal	**21,283**	**$22,298,477**	**42,428**	**34,273**	**206,605,616**	**667**	**$1,947,647**	**591,671**
Peak Controlled Rates	111	$668,319	24,159	12,182	939,653			
Saver's Switch	2,830	$1,963,115	25,385	7,697	67,514			
Load Management Subtotal	**2,941**	**$2,631,434**	**49,544**	**19,879**	**1,007,166**			
Energy Analysis	235	$292,574				99	$96,909	
Lamp Recycling	27,344	$29,632						
Indirect Impact Subtotal	**27,579**	**$322,206**				**99**	**$96,909**	
Business Segment Total	**51,803**	**$25,252,116**	**91,972**	**54,152**	**207,612,782**	**766**	**$2,044,557**	**591,671**
Residential Segment								
Central AC Quality Installation	5,000	$1,790,815	3,878	3,161	1,618,456			
Energy Star Rebates						5,900	$634,000	76,228
High-Efficiency Showerheads						12,273	$135,241	27,001
Home Efficiency	65	$111,603	258	31	292,802	341	$451,390	20,234
Home Lighting	46,559	$310,629	2,421	447	4,000,025			
Home Performance Rebates	50	$40,351	106	44	117,234	50	$150,414	1,522
Water Heater Rebates						800	$73,741	1,440
Conservation Subtotal	**51,674**	**$2,253,397**	**6,662**	**3,684**	**6,028,516**	**19,364**	**$1,444,786**	**126,425**
Saver's Switch	20,000	$5,674,608	60,302	24,378	279,720			
Load Management Subtotal	**20,000**	**$5,674,608**	**60,302**	**24,378**	**279,720**			
Consumer Education	379,750	$414,314				267,500	$69,996	
Home Energy Audits	9,303	$407,092				3,838	$179,557	
Lamp Recycling	154,949	$162,126						
Indirect Impact Subtotal	**544,002**	**$983,532**				**271,338**	**$249,553**	
Residential Segment Total	**615,676**	**$8,911,538**	**66,964**	**28,062**	**6,308,236**	**290,702**	**$1,694,339**	**126,425**
Low-Income Segment	**1,700**	**$910,453**	**432**	**86**	**970,031**	**546**	**$931,176**	**10,990**
Expected Alternative Filings	**450**	**$6,668,646**		**5,000**	**23,322,700**			
Planning & Research Segment								
Planning								
CIP Training		$61,704					$26,449	
DSM Regulatory Affairs		$768,617					$146,421	
Research								
CIP Market Research		$424,350					$160,713	
CIP Product Development		$400,000					$50,000	
Planning & Research Total		**$1,654,671**					**$383,583**	
Supply Side Resources Segment								
University of Minnesota IREE		$2,107,374					$185,903	
Supply Side Resources Total		**$2,107,374**					**$185,903**	
2007 TOTAL	669,629	$45,504,799	159,368	87,300	238,213,749	292,014	$5,239,557	729,086

Table C-3 (continued)
Xcel Energy's 2007-2009 Approved DSM Programs and Goals

2008	Electric Participants	Electric Budget	Customer kW	Generator kW	Generator kWh	Gas Participants	Gas Budget	MCF Savings
Business Segment								
Boiler Efficiency						351	$636,769	272,206
Compressed Air Efficiency	85	$869,263	2,814	2,500	19,498,705			
Computer Efficiency	19,164	$179,564	239	253	2,230,207			
Cooling Efficiency	362	$1,497,290	4,843	3,183	6,835,463			
Custom Efficiency	123	$3,690,695	6,627	5,387	35,928,505	31	$441,104	70,000
Energy Design Assistance	48	$5,549,231	9,396	9,276	39,999,971	11	$163,695	15,004
Energy Management Systems	77	$828,896	1,699	28	15,024,415	13	$50,009	5,122
Furnace Efficiency						132	$50,384	3,589
Industrial Efficiency	10	$1,976,001	2,811	2,637	15,620,426	2	$96,698	41,000
Lighting Efficiency	539	$3,006,216	7,106	6,395	32,881,623			
Motor Efficiency	450	$1,756,293	4,518	3,196	25,216,289			
Recommissioning	105	$1,615,111	1,991	948	12,991,982	37	$79,147	9,000
Segment Efficiency	401	$2,906,945	4,139	2,824	20,677,229	142	$110,391	31,487
Conservation Subtotal	**21,364**	**$23,875,505**	**46,184**	**36,628**	**226,904,815**	**719**	**$1,628,197**	**447,408**
Peak Controlled Rates	111	$678,831	24,159	12,182	939,653			
Saver's Switch	2,830	$1,999,194	25,385	7,697	67,514			
Load Management Subtotal	**2,941**	**$2,678,025**	**49,544**	**19,879**	**1,007,166**			
Energy Analysis	242	$296,807				99	$99,913	
Lamp Recycling	27,344	$29,704						
Indirect Impact Subtotal	**27,586**	**$326,511**				**99**	**$99,913**	
Business Segment Total	**51,891**	**$26,880,041**	**95,728**	**56,507**	**227,911,981**	**818**	**$1,728,110**	**447,408**
Residential Segment								
Central AC Quality Installation	7,000	$2,330,006	5,413	4,413	2,259,435			
Energy Star Rebates						5,900	$639,419	76,228
High-Efficiency Showerheads						11,136	$123,653	24,499
Home Efficiency	85	$129,477	357	92	391,283	422	$571,630	25,038
Home Lighting Direct Purchase	52,379	$352,663	2,724	503	4,500,039			
Home Performance Rebates								
Water Heater Rebates						900	$78,390	1,620
Conservation Subtotal	**59,464**	**$2,812,146**	**8,494**	**5,008**	**7,150,757**	**18,358**	**$1,413,092**	**127,386**
Saver's Switch	20,000	$6,401,602	60,302	24,378	279,720			
Load Management Subtotal	**20,000**	**$6,401,602**	**60,302**	**24,378**	**279,720**			
Consumer Education	391,143	$427,280				275,525	$72,006	
Home Energy Audits	9,769	$426,548				4,030	$184,997	
Lamp Recycling	154,949	$162,341						
Indirect Impact Subtotal	**555,861**	**$1,016,169**				**279,555**	**$257,003**	
Residential Segment Total	**635,325**	**$10,229,916**	**68,796**	**29,386**	**7,430,477**	**297,913**	**$1,670,095**	**127,386**
Low-Income Segment	**1,700**	**$963,861**	**432**	**86**	**970,031**	**546**	**$930,269**	**10,990**
Expected Alternative Filings	**450**	**$7,044,271**		**5,000**	**23,322,700**			
Planning & Research Segment								
Planning								
CIP Training		$62,758					$26,902	
DSM Regulatory Affairs		$786,232					$150,487	
Research								
CIP Market Research		$635,145					$194,353	
CIP Product Development		$400,000					$50,000	
Planning & Research Total		**$1,884,135**					**$421,742**	
Supply Side Resources Segment								
University of Minnesota IREE		$0					$0	
Supply Side Resources Total		**$0**					**$0**	
2008 TOTAL	689,366	$47,002,224	164,955	90,980	259,635,189	299,277	$4,750,216	585,784

Table C-3 (continued)
Xcel Energy's 2007-2009 Approved DSM Programs and Goals

2009	Electric Participants	Electric Budget	Customer kW	Generator kW	Generator kWh	Gas Participants	Gas Budget	MCF Savings
Business Segment								
Boiler Efficiency						351	$644,298	289,921
Compressed Air Efficiency	87	$909,079	2,887	2,564	19,999,275			
Computer Efficiency	19,164	$179,990	239	253	2,230,207			
Cooling Efficiency	373	$1,523,400	5,025	3,213	6,915,937			
Custom Efficiency	121	$3,675,477	6,484	5,270	35,143,655	25	$415,082	57,000
Energy Design Assistance	48	$5,549,231	9,396	9,276	39,999,971	11	$167,820	15,004
Energy Management Systems	82	$871,987	1,810	30	15,971,148	13	$51,217	5,122
Furnace Efficiency						132	$51,022	3,589
Industrial Efficiency	18	$3,152,213	5,019	4,709	27,893,617	4	$130,663	62,800
Lighting Efficiency	496	$2,911,006	6,569	5,913	30,394,789			
Motor Efficiency	450	$1,750,918	4,518	3,196	25,216,289			
Recommissioning	117	$1,759,010	2,219	1,056	14,476,779	40	$79,720	9,000
Segment Efficiency	109	$1,633,876	2,399	1,641	11,919,088	32	$61,787	18,043
Conservation Subtotal	**21,065**	**$23,916,186**	**46,565**	**37,123**	**230,160,756**	**608**	**$1,601,609**	**460,479**
Peak Controlled Rates	111	$689,577	24,159	12,182	939,653			
Saver's Switch	2,830	$2,012,602	25,385	7,697	67,514			
Load Management Subtotal	**2,941**	**$2,702,179**	**49,544**	**19,879**	**1,007,166**			
Energy Analysis	252	$312,894				103	$104,731	
Lamp Recycling	27,344	$29,780						
Indirect Impact Subtotal	**27,596**	**$342,674**				**103**	**$104,731**	
Business Segment Total	**51,602**	**$26,961,039**	**96,109**	**57,002**	**231,167,922**	**711**	**$1,706,340**	**460,479**
Residential Segment								
Central AC Quality Installation	9,000	$3,055,291	6,959	5,673	2,904,718			
Energy Star Rebates						5,900	$645,967	76,228
High-Efficiency Showerheads						10,681	$118,570	23,498
Home Efficiency	102	$149,575	428	111	469,539	594	$685,015	35,489
Home Lighting Direct Purchase	58,198	$389,768	3,026	559	4,999,967			
Home Performance Rebates								
Water Heater Rebates						1,000	$85,073	1,800
Conservation Subtotal	**67,300**	**$3,594,634**	**10,414**	**6,343**	**8,374,224**	**18,175**	**$1,534,625**	**137,015**
Saver's Switch	20,000	$6,113,468	60,302	24,378	279,720			
Load Management Subtotal	**20,000**	**$6,113,468**	**60,302**	**24,378**	**279,720**			
Consumer Education	402,877	$440,654				283,790	$74,000	
Home Energy Audits	10,258	$446,948				4,231	$189,997	
Lamp Recycling	154,949	$162,563						
Indirect Impact Subtotal	**568,084**	**$1,050,165**				**288,021**	**$263,997**	
Residential Segment Total	**655,384**	**$10,758,266**	**70,716**	**30,721**	**8,653,944**	**306,196**	**$1,798,622**	**137,015**
Low-Income Segment	**1,700**	**$999,398**	**432**	**86**	**970,031**	**546**	**$945,716**	**10,990**
Expected Alternative Filings	**450**	**$7,453,702**		**5,000**	**23,322,700**			
Planning & Research Segment								
Planning								
CIP Training		$63,851					$27,369	
DSM Regulatory Affairs		$896,374					$164,839	
Research								
CIP Market Research		$817,552					$152,618	
CIP Product Development		$400,000					$50,000	
Planning & Research Total		**$2,177,777**					**$394,826**	
Supply Side Resources Segment								
University of Minnesota IREE		$0					$0	
Supply Side Resources Total		**$0**					**$0**	
2009 TOTAL	709,136	$48,350,183	167,257	92,809	264,114,597	307,453	$4,845,504	608,484

C.3.3 Reasons Why Other Programs Were Not Implemented

On an on-going basis, we review our DSM programs and consider other programs to add to our portfolio. Programs are evaluated on their cost-effectiveness and ability to achieve a certain level of market response. These criteria are influenced by a variety of factors, including changes in state or federal efficiency standards, building codes, increased availability of high efficiency technologies, technological advances and general consumer acceptance. Programs must be cost-effective in order to be implemented.

C.4 Describe Major DSM Accomplishments

Xcel Energy is a nationally recognized leader in energy conservation and load management programs. In recent years, we have received the following awards for DSM programs:

- 2007 ACEEE Exemplary Program Awards for Lighting Efficiency, Energy Design Assistance, and Center for Energy and Environment's (CEE) One-Stop Efficiency Shop
- 2007 ACEEE Exemplary Program Honorable Mention for Custom Efficiency.
- 2006 Energy Star for Home Outstanding Achievement.
- 2005 Energy Star for Home Outstanding Achievement.
- 2003 Governor's Award for Excellence in Waste and Pollution Prevention for the CEE One-Stop Efficiency Shop.
- 2003 American Council for an Energy Efficient Economy Exemplary Natural Gas Conservation Program for the Energy Design Assistance and Boiler Efficiency Programs.

In addition, we have successfully managed cost-effective DSM programs for more than twenty years. We typically exceed energy efficiency goals established by the Department. From 1990 to 2006, the cumulative impact of these efforts is:

- Over $628 million in electric CIP expenditures;
- Over $2.4 billion in net utility benefits;
- 2,100 MW of demand-savings; and
- 4,100 GWh of energy-savings.

These achievements have avoided the construction of eight medium-sized (250 MW) power plants and saved enough energy to power half a million households. Furthermore, we have nearly 70 full-time employees across several areas of the company working together to design new conservation and load management programs, ensure that the savings estimates are

accurate and measurable, develop marketing materials that reach the right target markets, communicate with customers one-on-one about our programs, and create plans to ensure we meet our goals.

C.5 Describe Future DSM Plans Through the Forecast Years

As discussed in previous sections, the Next Generation Energy Act of 2007 significantly increases the Company's goal requirements beginning in 2010. Future CIP plans will reflect the new goals.

C.6 Quantify How These Programs Determine the Forecast Provided in Response to 7849.0270, subpart 2

Load forecasts are based on historical load data. Therefore, the forecasted annual peak demand for electricity and annual energy consumed inherently 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 on the forecast. This "amount" is known as embedded DSM and is roughly equal to the average annual DSM achievements obtained during the historical years. In addition to reflecting embedded DSM, the forecast is adjusted to account for the estimated savings from future DSM programs. Therefore, the total impact of DSM savings (both embedded and incremental) is fully incorporated in the forecast.

C.6.1 Total Costs by Program

The estimated costs of our Triennial programs are provided in Table C-3 above. Because the Company does not track its customers in the categories listed (farm, irrigation, non-farm residential, commercial, industrial, mining, street and highway lighting, electrified transportation, and other), we are unable to provide information specific to those customer groups. However, in general, the listed categories fall into the following customer segments:

- Commercial & Industrial includes Commercial, Industrial, Mining;
- Small Business includes Street and Highway Lighting and Electrified
- Transportation;
- Consumer and/or Low-Income includes Non-farm Residential.

C.6.2 Discuss the Expected Effects in Reducing the Need for New Transmission and Generation

Our existing and newly developed demand-side management programs are designed to help us achieve the goals established in the 2007/2008/2009 Triennial Plan and under the new legislation. The effects of our conservation and load management programs are incorporated into the forecast of energy and demand during the modeling stage. The peak demand savings from interruptible load (associated with interruptible and direct load control programs) is subtracted from the base peak demand forecast to obtain the "net generator peak" forecast.

Appendix D: Alternative Technologies Screening

This appendix provides a detailed screening of generation technology alternatives. The alternatives are examined primarily from the perspective of technology applicability and reliability. It also provides a high level overview of economic and environmental impacts associated with the technology. Technology options are grouped as follows:

- Fossil-Fuel Technologies;
- Renewable Resource Technologies;
- Composite Resource Technologies: These alternatives are combinations of technologies that may not pass the screening as an individual resource, but have been found to be a viable option when coupled with one or more additional, complimentary resources; and
- Developing Resource Technologies.

Generation technology options that are found to be appropriate in this initial technology screening are analyzed in more detail as alternatives to the preferred proposal.

D.1 Screening Factors

D.1.1 Applicability

Applicability of the technology refers to the technology's appropriateness for the Project's operating mode. One of the objectives of the Project is to provide energy and capacity for base load service. Other service modes include intermediate load and peaking load.

While there are no strict definitions for base load, intermediate, and peaking modes of operation, the following descriptions may be helpful:

Base load resources normally operate in the range of 50 percent to 100 percent annual capacity factor, with typical capacity factors of newer base load resources being in the range of 80 percent to 90 percent. Base load resources generally have few starts per year (<10) and may be operated at reduced output levels to follow system load during off-peak periods.

Intermediate resources normally operate in the range of 20 percent to 60 percent annual capacity factor, with typical capacity factors of newer intermediate resources being in the range of 40 percent to 50 percent. Intermediate resources generally have the most starts per year of any generation resource type (> 20 and sometimes > 200), depending on the requirements of the system it serves. In recent years, intermediate resources have largely been gas-fired combined cycle facilities or older coal-fired facilities that do not have low enough variable production costs to be dispatched on a continuous basis.

Peaking resources normally operate in the range of 0 percent to 20 percent annual capacity factor, with typical capacity factors of newer peaking resources being in the range of 5 percent to 10 percent. Peaking resources are usually started only when there are very high system loads or a system operating condition develops that requires the operation of such resources over a relatively short period of time. Peaking resources usually have less than 30 starts per year.

As large regional energy markets have continued to expand, it has become possible to combine several different types of resources to meet the particular needs of a given electric system. This is especially true of conventional resources coupled with intermittent resources such as wind generation. Base load needs, for example can be served with combinations of wind and gas-fired resources or wind and hydro resources. To the extent that there are intermittent gaps in energy production from wind resources, for example, gas-fired resources that are typically used in peaking or intermediate operating mode can be dispatched as needed. Additionally, energy from large regional energy markets may be economical in many or most of the hours in which wind energy production intermittency occurs in a given year.

D.1.2 Reliability

Reliability is screened from two perspectives: operational reliability and system reliability.

Operational reliability is primarily evaluated by the availability of an alternative, which is dependent upon many factors such as maintenance requirements and availability of fuel. For a facility designed to meet the need identified and contribute towards our carbon reduction goal, availability is a significant consideration.

The evaluation of the proposed Project and alternatives must also address the commercial availability of a particular alternative technology—one that has been commercially demonstrated to meet needs similar to those the Project has been designed to serve.

Another important factor is the alternative's implementation time. The primary activities that affect implementation time are obtaining necessary regulatory approvals, acquiring necessary transmission services, negotiating financing agreements, selecting and acquiring a site, design and engineering, procuring, construction, and testing facility equipment.

System reliability is examined from the perspective of the overall ability of an alternative to enhance the reliability of the bulk electric system. Reliability impact may be measured by an alternative's potential to reduce the frequency, duration and magnitude of adverse effects on the electric supply.

The North American Electric Reliability Council (NERC) defines reliability as follows[1]:

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[1] Ibid.

"The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system adequacy and security.

Adequacy—the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking in account scheduled and reasonably expected unscheduled outages of system elements.

Security—the ability of the electric system to withstand sudden disturbance such as electric short circuits or unanticipated loss of system elements."

D.1.3 Environmental Impacts

Environmental impacts refer to the effects the alternative is expected to have on the environment. Potential environmental impacts associated with generation technologies include air emissions, effects on land, water consumption, wastewater generation, noise, aesthetics, and traffic.

One measure of potential overall impact to the environment is the efficiency of the technology. Efficiency quantifies how completely one form of energy can be transformed into another form of energy that is more useful for a given purpose. Typically, for fossil fuel electric power generating facilities, efficiency is expressed in terms of a heat rate.

"Heat rate" is defined as[2]:

"a measure of average thermal efficiency of an electric generating facility expressed as the ratio of input energy per net kilowatt hour produced, computed by dividing the total energy content of fuel burned for electricity generation by the resulting net kilowatt hour generation."

This heat rate can be converted into an efficiency percentage by dividing 3413 by the heat rate (given in units of British thermal units per kilowatt-hour) and multiplying the results by 100. "Heat rate" and "efficiency" are inversely related (i.e., the lower the heat rate, the higher the efficiency). Therefore, energy conversion projects with lower heat rates are more efficient consumers of energy resources.

While heat rate or efficiency is not a direct measure of environmental impacts, a more efficient technology many times uses fewer natural resources and may have lower environmental impacts (e.g., fewer air emissions) per kilowatt-hour of energy produced.

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[2] Minn. Rules 7849.0010, Subp. 12.

D.1.4 Economic Effects

Economic effects of the alternatives may include jobs created during construction and during ongoing operations, effects on regional economic development, and effects on tax revenues generated.

D.2 Fossil-Fuel Technology Screening

D.2.1 Supercritical Pulverized Coal-Fired Boiler

A supercritical pulverized coal-fired steam power plant consists of a steam boiler, a steam turbine and an electric generator side. In the simplest terms, steam is generated when water is heated by the thermal energy released when pulverized coal is burned in the boiler. The steam from the boiler is piped to, and drives, a steam turbine, which in turn drives an electric generator. The term "supercritical" refers to a particular range of thermodynamic conditions (pressure and temperature) under which such a plant is designed to operate. Supercritical boilers are typically several percentage points more efficient than boilers not designed to operate under supercritical conditions.

A pulverized coal plant includes the following components:

- A large boiler that combusts coal and generates steam.
- A steam turbine generator that converts the steam's thermal energy into electrical energy.
- A coal handling system that provides coal to the boiler.
- A water treatment system that provides high quality water to the boiler steam cycle.
- A system (e.g., a cooling tower or dry cooling) to condense the exhaust steam from the steam turbine generator.
- Air pollution control equipment necessary to comply with State and Federal standards governing flue gas emissions.
- An ash disposal system that collects and stores waste ash from the coal combustion process.
- Distributed control systems to control plant equipment.
- Operations and maintenance buildings.

Fuel for the plant (coal) is typically brought to the plant by railroad or barge. Natural gas is often used as a secondary fuel and is transported to the facility via pipeline. A significant source of cooling water is required for condensing the exhaust steam from the steam turbine generator and for quenching ash produced in the boiler.

D.2.1.1 Applicability

Pulverized coal-fired facilities are best suited for base load (steady, high-capacity factor operation); however they may also serve as intermediate resources. Coal-fired units are not well suited to operate as peaking plants because of the length of time necessary for start-up (which can be a day or more) to bring a coal-fired plant on-line at full capacity. In addition, their relatively high capital costs would become prohibitive if spread over the sub-20 percent typical capacity factor of a peaking resource.

D.2.1.2 Reliability

Pulverized coal-fired power plants are typically expected to have an annual outage rate for maintenance of 11 percent. Unplanned outages typically consume another 4 percent of the unit's availability. The net availability of coal-fired units is expected to be in the range of 85 percent. Thus, a pulverized coal-fired plant can generally demonstrate high reliability.

D.2.1.3 Environmental Impacts

Viewing environmental impacts indirectly in terms of energy efficiency (input fuel energy per kilowatt hour produced), pulverized coal-fired plants typically operate in a range of 32 to 35 percent efficiency. When designed for supercritical operating conditions, a pulverized coal-fired plant can be up to 37 percent efficient. The direct environmental impacts of coal burning include air emissions, solid waste (ash) generation, waste-heat discharge to air and water, and rail or barge traffic.

Typical carbon dioxide emission rates for new supercritical pulverized coal units are in the range of 200 lb CO2 per million btu heat input.

D.2.1.4 Economic Effects

Typically, a supercritical pulverized coal-fired power plant has high capital costs and relatively low fuel costs. Thus, it is most economically viable when serving a need for a high capacity factor resource.

Building a coal-fired power plant is a major undertaking with 12 to 24 months needed for environmental and site permitting and 36 to 60 months for construction thereafter. Transmission system upgrades necessary to accommodate a large base load facility may take 5 to 10 years to complete.

While the peak construction work force can easily exceed 1,000 personnel depending upon plant size, its contribution to the local economy is temporary. A utility-scale pulverized coal-fired generating unit typically employs 100 or more permanent staff while in operation. Power plants in Minnesota are assessed a significant local personal property tax that usually offsets some of the tax burden on other local enterprises.

D.2.2 Integrated Gasification Combined Cycle Utilizing Coal

An integrated gasification combined cycle (IGCC) power plant consists of a coal gasifier, a combustion turbine, a heat recovery steam generator and a steam turbine. In the gasifier, coal is heated to produce a "syngas" that is burned in a combustion turbine that turns a generator to produce electricity. Waste heat in the exhaust gases from the combustion turbine are used to produce steam in a heat recovery steam generator. Steam from the heat recovery steam generator is piped to, and drives, a steam turbine, which in turn drives an electric generator also.

An IGCC coal plant includes the following components:

- A gasifier that produces syngas from coal.
- A combustion turbine that burns the syngas and generates electricity.
- A heat recovery steam generator that produces steam from the waste heat in the exhaust gases from the combustion turbine
- A steam turbine that converts the steam's thermal energy into electrical energy.
- A coal handling system that provides coal to the gasifier.
- A water treatment system that provides high quality water to the heat recovery steam generator.
- A system (e.g., a cooling tower or dry cooling) to condense the exhaust steam from the steam turbine generator.
- Air pollution control equipment necessary to comply with State and Federal standards governing flue gas emissions.
- An ash disposal system that collects and stores waste ash from the gasifier.
- Distributed control systems to control plant equipment.
- Operations and maintenance buildings.

Fuel for the plant (coal) is typically brought to the plant by railroad or barge. Natural gas is often used as a secondary fuel and is transported to the facility via pipeline. A significant source of cooling water is required for condensing the exhaust steam from the steam turbine generator.

D.2.2.1 Applicability

IGCC plants are best suited for base load operating mode (steady, high-capacity factor); however they may also serve as intermediate resources. IGCC units are not well suited to operate as peaking plants because of the length of time required for start-up (which can be a day or more) to bring the plant on-line at full capacity. In addition, their relatively high capital costs would become prohibitive if spread over the sub-20 percent typical capacity factor of a peaking resource.

D.2.2.2 Reliability

IGCC technology utilizing low rank (sub-bituminous Powder River Basin) coal is a relatively new application with very limited operating data available. U.S. IGCC manufacturers claim planned maintenance and forced outage superior to supercritical pulverized coal plants with a resulting availability in range of 85 percent to 92 percent. Although these claims are somewhat untested, manufacturers are increasingly willing to offer performance guarantees to support their availability claims.

An IGCC plant is expected to demonstrate high reliability (both the adequacy and security aspects), but further operating experience is necessary to validate that expectation.

D.2.2.3 Environmental Impacts

IGCC plants are predicted to typically operate in the range of 35 percent to 40 percent efficiency. The direct environmental impacts of coal gasification include air emissions, solid waste (ash) generation, waste-heat discharge to air and water, and rail traffic.

Without CO2 sequestration, an IGCC plant is projected to have similar CO2 emissions to a supercritical pulverized coal generating plant (in the range of 200 lb CO2 per million btu fuel consumed). However, CO2 sequestration would also add significantly to the project's costs.

D.2.2.4 Economic Effects

Industry publications generally assume the costs for a new IGCC power plant to be approximately 20 – 40 percent higher than for pulverized coal plants.

Building an IGCC power plant is also a major undertaking with 12 to 24 months needed for environmental and site permitting and 36 to 48 months for construction thereafter. Transmission system upgrades necessary to accommodate a large base load facility may take 5 to 10 years to complete.

While the peak construction work force can easily exceed 1,000 personnel, its contribution to the local economy is temporary. A utility-scale IGCC generating unit is expected to employ 50 or more permanent staff while in operation. Power plants in Minnesota are assessed a significant local personal property tax that usually offsets some of the tax burden on other local enterprises.

D.2.3 Advanced Natural Gas-Fired Combined Cycle

A gas-fired combined cycle power plant is a combination of combustion turbine technology, heat recovery and electric generation. In the combustion turbine, incoming air is compressed and mixed with the natural gas fuel. Igniting this mixture results in an expansion of gases (the combustion products and excess air) through a power turbine that in turn drives an electric generator. Hot exhaust gases exiting the combustion turbine pass through a heat recovery steam

generator (HRSG) to produce steam that is used to drive a steam turbine connected to a second electric generator.

Advanced gas-fired combined cycle generating units utilize large, highly efficient combustion turbines constructed with some "exotic" materials. These materials are designed to withstand the extreme operating conditions necessary to achieve high efficiency. To date, these materials have had a relatively low tolerance for thermal cycling, so combustion turbine manufacturers severely limit the number of starts per year when warranting performance of *advanced* combined cycle equipment.

Other major advanced combined-cycle plant equipment would include:

- A system (e.g., condenser or cooling tower) to condense the steam turbine exhaust steam.
- A water treatment equipment to provide high-quality makeup water to the steam cycle.
- Electrical switchgear to provide power to auxiliary plant equipment.
- Water storage tanks and fuel oil storage tanks (if applicable).
- Natural gas vaporizers.
- Possible ammonia storage if post-combustion NOx control is required.
- Operations and maintenance buildings.

D.2.3.1 Applicability

Advanced combined cycle plants are technically well suited to meet base load needs. The benefits of high efficiency must be weighed against the cost of operating such facilities on relatively high cost natural gas or fuel oil. Operating in intermediate mode will void performance warranties for new advanced combined cycle units and result in exceptionally high maintenance costs after the warranty period has expired. Thus, operation of an advanced combined cycle unit in intermediate mode is not advised. An advanced combined cycle unit can be operated in peak mode if the number of starts per year were carefully managed. However, there are more economic alternatives for peak mode operation of a gas-fired resource than an advanced combined cycle unit.

D.2.3.2 Reliability

Properly operated and maintained, combined-cycle facilities will achieve high availability. Natural gas-fired combined cycle facilities typically have fuel oil backup to address the potential interruption of natural gas supply.

A combined-cycle plant can also generally demonstrate high reliability (both the adequacy and security aspects). Natural gas-fired combined cycle facilities typically have fuel oil backup to address the potential interruption of natural gas supply.

D.2.3.3 Environmental Impacts

Environmental impacts in terms of energy efficiency (input fuel energy per kilowatt-hour produced) show distinct advantages for a combined-cycle project vs. a coal-fired plant. The energy efficiency for a combined cycle plant can be expected to be in the range of 45 to 50 percent with the efficiency of an advanced combined cycle plant exceeding 50 percent.

The direct environmental impacts of operating a combined-cycle plant burning natural gas include air emissions, wastewater discharge, waste heat discharge to air and water and the potential for on-site ammonia storage if post-combustion NOx control is required. Air emissions from an advanced gas-fired combined cycle plant are lower than that of a coal-fired plant, especially in terms of SO2 and CO2 (150 lbs per mmbtu of fuel input). A gas-fired combined cycle plant does not produce any ash.

D.2.3.4 Economic Effects

The total capital requirement for a hypothetical advanced gas-fired combined-cycle power plant are less than for pulverized coal or IGCC. However, the fuel costs are higher and subject to significant variability and volatility.

The permitting and construction time needed for an advanced combined cycle plant is typically 12 to 18 months for permitting and 24 to 36 months for construction. Transmission upgrades to accommodate such a facility on the system may take more than 5 years. While the construction work force is sizeable (> 500 at construction peak), its contribution to the local economy is temporary. A combined-cycle unit fired with pipeline natural gas will require significantly fewer staff than a corresponding coal-fired facility having to deal with major coal and ash handling operations. Thus, a combined cycle plant is not regarded as having a key impact on long-term local employment rates. A combined cycle plant would be subject to applicable property tax assessments.

D.2.4 Simple Cycle Combustion Turbine

A simple cycle power plant uses natural gas as its primary fuel and may use fuel oil as a backup fuel during times of gas supply interruption. A simple cycle combustion turbine is less expensive per KW of capacity and also significantly less efficient than a combined cycle facility because the heat from the combustion turbine exhaust gases is not recovered for secondary electric generation from a steam turbine. Ancillary equipment is likely limited to:

- Natural gas vaporizers.
- Possible ammonia storage if post-combustion NOx control is required.
- Control buildings.
- Fuel oil storage tanks (if applicable).

- A fuel forwarding system (pumps/piping/controls) to transfer fuel oil from storage to the turbine.
- Fuel heating systems for winter operations.

D.2.4.1 Applicability

Simple cycle plants are typically employed for peaking duty and are not well suited to economically meet intermediate and base load needs. Simple cycle combustion turbine generators exceeding 20 percent capacity factor would likely defer to intermediate load facilities or be considered for conversion to a combined cycle unit. Advantages of simple cycle turbine generators include flexibility in siting, relatively low capital cost and, a relatively short construction period.

D.2.4.2. Reliability

Properly operated and maintained turbine facilities will achieve high availability.

At the expense of dispatch economics, a simple cycle plant can generally demonstrate high reliability (both the adequacy and security aspects). A simple cycle combustion turbine facility may utilize fuel oil as a backup to address the potential interruption of natural gas supply. However, environmental permitting may be substantially complicated if fuel oil is utilized as a back-up fuel due to the potential for higher air emissions related to there being more sulfur in fuel oil than in natural gas. This consideration limits siting flexibility for additional units at existing peaking plant sites and/or near areas that have little available room to permit any additional air emissions.

D.2.4.3 Environmental Impacts

Environmental impacts in terms of energy efficiency (input fuel energy per kilowatt-hour produced) would not show a distinct advantage for a simple cycle turbine-driven project vs. a combined-cycle plant or a coal-fired plant. The energy efficiency for simple cycle combustion turbine generator can be expected to be in the range of 25 to 30 percent. The direct environmental impacts of operating a simple cycle plant burning natural gas include air emissions, waste heat discharge via the stack and the potential for on-site ammonia storage if post-combustion NO_x control is required.

D.2.4.4 Economic Effects

The total capital requirement for a simple-cycle gas-fired combustion turbine power plant installation is much lower than for other fossil-fuel technologies. However, the typical energy cost for a simple-cycle gas-fired combustion turbine power plant is estimated to be much higher than for other fossil fuel units, making it a better option for meeting low capacity factor needs.

Building a simple cycle power plant is a major construction project with about a 12-18 month time frame for permitting and 12 months for construction. The time required to implement transmission upgrades necessary to accommodate the output of such a facility is highly variable, depending on the particular site chosen. The positive impact of the construction work force on the local economy is temporary. A simple cycle unit fired with pipeline natural gas will require significantly fewer staff than a corresponding coal-fired facility having to deal with major coal and ash handling operations. Thus a simple cycle plant could not be regarded as having a key impact on long-term local employment rates. Certain components of a simple cycle driven power plant would be subject to local property tax assessments.

D.2.5 Summary of Fossil-Fuel Technologies

Based on this initial screening, several fossil-fuel technologies have similar operating characteristics (base load) of the Monticello nuclear plant. However none of these can be economically built to a similar size as the uprate project. Also, with the exception of the simple cycle combustion turbine, none of the fossil-fueled could likely be constructed in time to meet the 2011 in-service date of the uprate project. Therefore none of the typical fossil fuel technologies were include in the second stage quantitative evaluation as stand alone construction projects. However, while we are unaware of a specific project that would be available in 2011, we did include, due to the similar operating characteristics between coal and nuclear generation, we did include an equivalent sized (71 MW) coal purchased power contract in the quantitative evaluation for direct comparison.

D.3 Renewable Resource Technology Screening

D.3.1 Wind

Wind energy technology consists of a set of wind-driven turbine blades that turn a mechanical shaft coupled to a generator, which in turn produces electricity. The major components of the wind turbine include:

- Rotor blades
- Gear box
- Generator
- Nacelle (gearbox/generator housing)
- Tower
- Collection system of electrical lines connecting a number of wind turbines to a substation (applicable only to multiple wind turbine projects).

Wind turbines are either horizontal axis or vertical axis machines, which make full use of lift-generating air flows. Each type of turbine has advantages and disadvantages. The vast majority of wind turbines on the market currently utilize horizontal axis technology. Horizontal axis turbines are typically built with two or three turbine blades. Turbines for utility applications are normally installed in clusters of 5 to 200 megawatts, and may be referred to as wind farms.

D.3.1.1 Applicability

Wind turbines can help meet overall system energy needs, but offer inadequate dispatch flexibility to support intermediate or peaking load needs. Wind generation can help meet base load energy needs, but cannot meet the capacity component of base load needs on its own; it must be coupled with other technologies or resources from the energy markets.

Utilization of taller wind turbine towers and the ever-greater geographic diversity of wind resources in the region will reduce the intermittency of wind generation on a system-wide basis and, thus, offer a correspondingly greater capacity contribution to base load capacity needs. However, such outcomes are still in the study phase and subject to validation over time.

D.3.1.2 Reliability

Wind turbines are generally expected to have a high availability, but actual availability is dependent on the quality of wind resources of the geographic location in which the resource is located. Even when wind energy is present, wind turbines can only generate power within an optimum range of wind speeds.

A wind turbine installation cannot have an objective of providing a guaranteed performance from the perspective of the utility customer. At best, wind-generated power can replace a percentage of base load generation during periods of low to moderately high wind conditions and subsequently conserve fossil fuels. The use of wind energy to meet base load or intermediate load needs is best when coupled with additional generation resources.

D.3.1.3 Environmental Impacts

Wind turbine generation has many environmental advantages over fossil fuels because there are no air emissions nor solids or water discharges associated with operating the turbines. Turbines may encounter some siting opposition with regard to noise and aesthetics. In many cases, the original use of the land (i.e., agriculture) can continue in the presence of the turbine installation with less than 5 percent of the original land area taken out of production.

D.3.1.4 Economic Effects

The total costs associated with wind vary according to market conditions. Two important factors are the availability of the production tax credit and supply conditions for wind turbines.

Building a wind farm project, like other power projects, would utilize a significant work force for the duration of the construction. Operating a wind farm does not require a large staff. Wind power electricity often qualifies for tax credits or production incentives on a cents-per-kilowatt basis.

Permitting and construction for large wind turbine installations can be completed in as little as 12 to 24 months. However, transmission upgrades necessary to accommodate energy production from wind turbines may take as long to implement as transmission upgrades for other base load options, particularly in areas where significant wind generation development has already occurred (i.e., Buffalo Ridge) or where little or no transmission infrastructure currently exists.

D.3.2 Solar

Solar energy to electricity conversion technologies include thermal conversion (typically using sunlight to generate steam to turn a turbine) and photovoltaic (direct conversion of sunlight to direct current power). Thermal, or concentrating solar power technology (parabolic troughs, power towers, and dish/engine systems), converts sunlight into electricity efficiently with minimal effects on the environment. Trough systems predominate among today's commercial solar-powered plants.

Trough systems focus the sun at 30 to 60 times its normal intensity to heat a heat transfer fluid (synthetic oil). The hot oil is pumped to a generating station heat exchanger to produce steam. Finally, electricity is produced in conventional steam turbine generators. Trough systems may be configured as hybrids to operate on natural gas on cloudy days or after dark.

The "photovoltaic effect" is the basic physical process through which a photovoltaic (PV) cell converts sunlight into electricity. Solar energy (composed of photons) is transferred to the electrons of atoms making up the PV cell. Higher energy electrons begin to flow and become electric current. By grouping single PV cells into arrays, and then placing many arrays together, power plants of up to 6.5 megawatts have been built.

D.3.2.1 Applicability

The applicability for solar generation to meet capacity needs is defined primarily by problems with reliability. Solar power systems generally represent even less capacity than a wind turbine installation and, combined with a dependence on quality insolation rates, cannot meet intermediate load and peaking service needs. Siting of a large solar power plant is also predicated on locating candidate areas that have the solar energy data that would support the project economics. The Southwest United States, rather than Minnesota, is usually considered the prime location for significant solar generation efforts.

D.3.2.2 Reliability

Solar generating facilities are generally expected to have a high availability, but actual availability is dependent on the quality of solar resources of the geographic location in which the resource is located.

A solar power installation cannot meet an objective of providing a guaranteed performance to the end user of generated power. The hybrid design of some solar plants, utilizing natural gas during periods of poor solar intensity, acknowledges that solar energy cannot be depended upon to maintain a capacity rating.

D.3.2.3 Environmental Impacts

Solar power generation has many environmental advantages over fossil fuels because there are no air emissions or solids discharges associated with operating the systems. Trough/gas hybrid systems do utilize a steam loop, which requires process and cooling water, some water treatment and some wastewater discharge (blowdown).

D.3.2.4 Economic Effects

The total capital requirement for either a photovoltaic power plant or a trough/gas hybrid plant continues to be significantly higher than for other resources, making it cost prohibitive for large-scale applications. Building a solar generation project, like other power projects, could utilize a significant work force for the duration of construction. Operating solar generation facilities does not require employing a large staff.

D.3.3 Biomass (Direct-Fired)

The process of direct-firing biomass fuels is very similar to the firing of other solid fuels. Fuel handling and storage, fuel firing, ash handling and disposal, air emissions, water consumption, and wastewater management will have many similarities to coal-fired systems. The primary activity steps for a biomass plant include:

- Biomass fuel receiving;
- On-site processing (size reduction, drying, screening);
- Fuel storage/conveying;
- Boiler (usually a stoker design);
- Ash and flue gas handling;
- Air emission controls (baghouse/ESP for particulate; ammonia for NO_x control);
- Steam turbine; and

- Cooling tower.

Biomass fuels can be harvested from the forest, collected as waste materials from processing plants or agriculture, or grown in biomass plantations. Fuel may be shipped to the power plant by truck, rail or barge depending on the plant location and type. Fuel will generally be stockpiled as insurance against interruptions in supply. Depending on fuel characteristics, drying and size reduction may be necessary prior to firing. Drying is sometimes accomplished by utilizing the heat from stack gases. Prepared fuel is fed to the furnace and the resulting heat is used to generate steam. The steam from the boiler is piped to, and drives, a steam turbine, which in turn drives an electric generator to produce saleable electrical power.

D.3.3.1 Applicability

A biomass facility may serve as an intermediate load unit; however, biomass-fired power boilers are best suited for base load (steady, high-capacity) duty. Boiler-based biomass-fueled plants are not well suited to operate as peaking plants because of the long lead time (a day or more) necessary to bring a solid fuel-fired plant on-line at full capacity. The forest products and agriculture industries in Minnesota and the Midwest offer a wide and expanding variety of biomass fuels.

D.3.3.2 Reliability

The net availability of biomass-fired units is expected to be reasonably high, potentially 85 percent.

A biomass-fired plant can generally demonstrate high reliability (both the adequacy and security aspects) for base load and intermediate load service if an adequate supply of fuel is available. Overcoming the logistical and economic challenges of collecting enough fuel to support the operation of a biomass-fueled power plant at a nominal 85 percent capacity factor is a substantial undertaking. Competition for economic fuel feedstocks can be fierce, depending on the feedstock(s) in question and the location of the biomass-fueled plant. This has been especially true of forest product waste fuels and urban wood waste fuel feedstocks.

D.3.3.3 Environmental Impacts

Waste streams from the furnace include stack gases, bottom ash, and boiler water blowdown. Bottom ash produced in many biomass combustion plants is often of a quality that can be sold, or used as a soil conditioner/fertilizer due to the lack of many trace metals, which often contaminate coal ash. Boiler blowdown, along with other process wastewater streams, will typically be treated to remove solids, oils, and grease prior to discharge. Cooling water used to condense the steam exhausted from the turbine would most likely be cooled using a direct-contact cooling tower. The use of a cooling tower represents a significant consumption of water.

The stack gases will contain particulate matter as well as gaseous pollutants – depending upon the fuel source used. If a thermal drier with auxiliary firing is used, the drying step will increase energy use and environmental emissions. Typically, stack gases will pass through an air pollution control device where particulate matter is removed. A large new boiler will likely be required to also address the control of NOx and CO emissions.

Viewing environmental impacts indirectly in terms of energy efficiency (input fuel energy per kilowatt hour produced), biomass-fired plants typically operate in a range of 20 – 30 percent efficiency. Biomass power production is affected by a greater variability in biomass fuel quality than is coal-fired power production. Variability in moisture and ash content are characteristic of a diverse fuel source and leads to variability in heat value on a mass basis. The direct environmental impacts of biomass burning are similar to those for coal combustion and include air emissions, solid waste (ash) generation, waste heat discharge to air and water, and truck and/or rail traffic.

A biomass plant utilizing a closed-loop biomass fuel, such as switchgrass or hybrid poplar trees, would have less environmental impact per unit of energy produced with regard to CO2 emissions because the uptake of CO2 during the growth of fuel feedstocks would offset CO2 emissions from the plant when the fuel was burned.

D.3.3.4 Economic Effects

The total capital requirement for a biomass power plant is highly variable and size dependent. Higher capacity plants will generally be less expensive. Due to the variability, it is important to analyze specific proposals before making cost estimates. Building a biomass-fired power plant is a major construction project with 12 to 24 months required for permitting and 24 to 36 months for construction. Transmission upgrades necessary to support such a project could take as long to implement as the transmission upgrades for other types of base load options. The relatively small size of biomass power plants (under 100 MW) could minimize the transmission upgrades implementation timeframe.

While the construction work force is of a significant size, its contribution to the local economy is temporary. The long-term operation of a biomass power plant would not be regarded as having a large impact on local employment rates via plant staffing. The creation of a (larger) biomass-for-fuel market may be an opportunity for farmers and landowners to exploit biomass materials that would otherwise be neglected as an income-producing source.

The plant would be subject to applicable property taxes that can be viewed as likely offsetting the tax burden on other local enterprise.

D.3.4 Hydropower

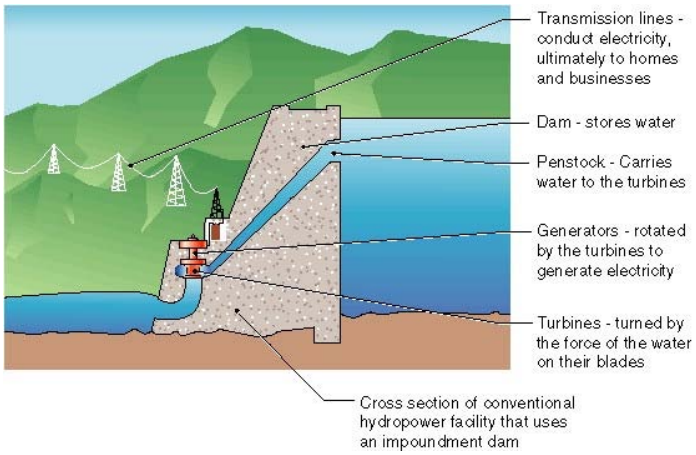
Hydroelectric power plants convert the potential energy of water, pooled at a higher elevation, into electricity by passing the water through a turbine and discharging it at a lower elevation. The water turns the turbine connected to an electric generator, thus producing electrical energy. The turbines and generators are installed in, or adjacent to, dams, or use pipelines (called penstocks) to carry the pressurized water below the dam or diversion structure to the powerhouse. Hydropower projects are generally operated in a run-of-river, peaking, or storage mode.

Run-of-river projects use the natural flow of the river and produce relatively little change in the stream channel and stream flow. A peaking project impounds and releases water when the energy is needed. A storage project extensively impounds and stores water during high-flow periods to augment the water available during low-flow periods, allowing the flow releases and power production to be more constant. Many projects combine the modes.

The capacity of a hydropower plant is primarily a function of two variables: (1) flow rate expressed in cubic feet per second (cfs); and (2) hydraulic head which is the elevation difference the water falls in passing from the reservoir through the turbine. Depending on the particular waterway being considered, project design may concentrate on either of these variables (high head/low flow or low head/high flow). Most conventional hydropower plants include the following major components:

- Dam — controls the flow of water and increases the elevation to create the heat. The reservoir that is formed is in effect stored energy.
- Penstock — carries water from the reservoir to the turbine in a power plant.
- Turbine — turned by the force of water pushing against the blades.
- Generator — connects to the turbine and rotates to produce the electrical energy.

The principal advantages of using hydropower are its large renewable domestic resource space, the absence of polluting emissions during operation, its capability in some cases to respond quickly to utility load demands, and its very low operating costs. Disadvantages can include high initial capital costs and potential site-specific and cumulative environmental impacts.



D.3.4.1 Applicability

Hydroelectric plants are operated in several modes. Plants with large water storage capability lend themselves well to peaking power production and hydroelectric plants are able to come on line much quicker than steam generating systems. Run-of-river plants are more likely to produce a more constant power output though that output is dependent on water levels and, in cold climates, ice conditions.

The U.S. Department of Energy's (DOE) Hydropower Program has estimated that there is additional hydropower in this region. While it is possible that some of the identified potential hydropower could be developed, decisions to do so would need to also consider that transmission systems may not exist in remote areas containing hydropower potential. Development of hydropower, and associated transmission systems, faces the scrutiny of a general environmental trend toward releasing water reservoirs where possible. Developing capacity of a hundred MW or more would require development of multiple existing and/or potential hydropower sites. Such an effort would take several years of environmental study and negotiation to acquire water use and land rights, and permits and licensing for dams and/or transmission lines.

D.3.4.2 Reliability

During periods of normal precipitation and ice-free conditions, the availability of established hydropower generation is typically very high.

The hydropower sector of power generation is well established with proven technologies installed as standard design. In mechanical terms, hydroelectric plants are highly reliable.

Because hydropower depends on water flow, hydroelectric plants are susceptible to fluctuations in output as a function of weather patterns. Reliability can suffer during periods of drought or during periods of freezing conditions in northern climates. Weather-induced fluctuation in power output may be less pronounced than it is for wind or solar power; however, for long-term planning to meet projected demand, hydropower may be better suited to reliably provide peak load capacity.

D.3.4.3 Environmental Impacts

Hydropower projects are not sources of the typical air and water emissions and solid waste disposal issues associated with solid fuel-fired power production; however, hydropower has faced scrutiny for its significant environmental impacts. More recent projects benefited from early experience to be able to minimize or offset impacts of altered river basin hydrology, fish mortality, fish migration interference, decrease in water quality, and flooding of land.

D.3.4.4 Economic Effects

The total capital requirement for a hypothetical hydropower power plant can be very high, although the all-in energy requirements are reasonable as compared to other alternatives. Most of the potential sites within the region have capability of less than 10 MW and economies of scale would not be realized. Annual operating expenses would likely be less than for a fuel-fired power plant because the hydropower energy source (pooled water) is not typically a purchased input.

Building a hydroelectric power plant is a major construction project with a several-year time frame. While the construction work force is of a significant size, its contribution to the local economy is temporary. The long-term operation of a hydroelectric power plant would not be regarded as having a large impact on local employment rates via plant staffing. The creation of a new reservoir does have the potential for creating commerce from recreational activity if fisheries and surrounding land area are developed to attract the public.

D.3.5 Landfill Gas

The most common use of landfill gas (LFG) is for on-site electricity generation by firing stationary engine generator sets. Some LFG is used to fire boilers or turbines and LFG, sufficiently processed, could be an energy source for fuel cell operation. Electric generating plants using LFG and those using natural gas or distillate oil are nearly identical; however, firing LFG does require gas processing and careful monitoring of equipment because LFG tends to be more corrosive. Significant quantities of LFG are emitted from municipal solid waste where it has been deposited in landfills; however, LFG typically has a medium Btu content and is not typically a source of energy on a scale larger than a few MW.

LFG recovery for energy is practiced in the United States, Europe and other countries around the world. A typical system consists of the following components[3]:

- The gas collection system, typically a series of wells strategically placed throughout the landfill, which gathers the gas being produced within the landfill;
- The gas processing system and engine/generator set, which cleans the gas and converts it into electricity; and

[3] U.S. Department of Energy/National Renewable Energy Laboratory, a DOE national laboratory; DOE/CH10093-322; DE94006897; May 1994, Revised October 1994; http://www.eren.doe.gov/cities_counties/landfil1.html

- The interconnection equipment, which delivers the electricity from the project to the final use.

D.3.5.1 Applicability

LFG power generation projects are generally sited on large landfills and produce power in the range of kilowatts to a few megawatts. The driver for LFG power generation is the utilization of a fuel source that would otherwise be flared to avoid an explosion hazard and to avoid an emission source by producing saleable energy. A LFG plant could reasonably be viewed as an emission control technology. LFG does not exist at the levels needed to support large energy needs.

D.3.5.2 Reliability

The availability of a LFG-fired generation system is expected to be high, similar to systems firing natural. However, the corrosive nature of landfill gas does introduce more potential for equipment problems.

Because of the small-scale nature of most LFG plants, a LFG power installation project typically does not have an objective of providing a guaranteed performance from the perspective of the utility customer. Power output for LFG plants depends upon the LFG production rate that does not adjust to power demand. LFG-generated power can replace a percentage of base load generation and subsequently conserve fossil fuels.

D.3.5.3 Environmental Impacts

LFG projects are expected to be a net benefit to the environment by reducing the amount of LFG emissions to the atmosphere; however, some of the landfill emission reductions are offset by the combustion emissions such as NO_x and CO from the combustion equipment. From an energy efficiency perspective, LFG collection systems (i.e., the well networks) are not totally efficient, and combined with the inherent inefficiencies of combustion equipment, the overall energy efficiency of an LFG system generally less than 30 percent.

D.3.5.4 Economic Effects

The total capital requirement for developing a hypothetical LFG power plant is not very high and all-in costs are also quite competitive. However, the LFG volumes do not exist within one site necessary to fuel a plant with a hundred MW or higher capacity. Most landfill sites will not support more than 10 MW of generation. Annual operating expenses may be less than for a typical fuel-fired power plant because the LFG is not typically a purchased input. However, some municipalities associated with landfills may require a royalty to be paid from energy sales.

The long-term operation of a LFG power plant would not be regarded as having a large impact on local employment rates via plant staffing.

Because of its limited availability, LFG is not a viable alternative for our current need. However, it performs well as a resource and we will continue to evaluate all LFG projects as they arise and pursue cost-effective landfill gas opportunities.

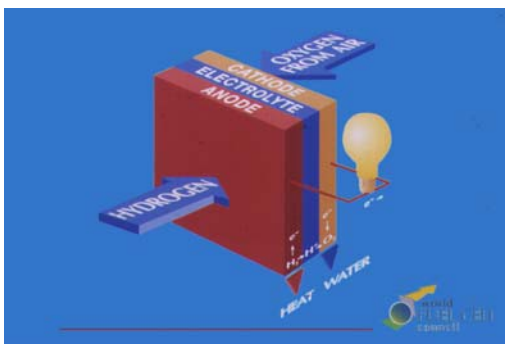
D.3.6 Summary of Renewable Resources

Based on the initial screening, only the biomass alternative has the appropriate characteristic to be included in the second stage quantitative analysis. The wind and solar options do not have comparable reliability due to the variability of the energy production. The hydro resource cannot be expected to be available in time for the 2011 in-service date. The landfill gas option likely cannot be acquired in sufficient quantity to provide the equivalent size and capacity to the Monticello upgrade project.

D.4 Developing Technologies Screening

D.4.1 Fuel Cells

A fuel cell converts energy directly, without combustion, by combining hydrogen and oxygen electrochemically to produce water, electricity, and heat. Fueled with pure hydrogen, they produce no pollutant emissions. Even if fueled with natural gas as a source of hydrogen, emissions are orders of magnitude below those for conventional combustion generating equipment. The principle of operation of a typical fuel cell consists of the following processes:



- When hydrogen is fed into a fuel cell a catalyst on the anode converts hydrogen gas into negatively charged electrons (e^-) and positively charged ions (H^+).
- The electrons (e^-) flow through an external load to the cathode.
- The hydrogen ions (H^+) migrate through the electrolyte to the cathode where they combine with oxygen and the electrons (e^-) to produce water.

There are a variety of fuel cell designs (referring mainly to the electrolyte style) including solid oxide, alkaline, phosphoric acid, molten carbonate, and proton exchange membrane. The main components of a fuel cell system include:

- A porous anode (example materials are graphite, and nickel, chromium and zirconium alloys);

- An electrolyte (example phosphoric acid)
- A porous cathode (same materials as anode);
- Precious metal catalyst;
- Fuel reformer (to generate hydrogen from fossil fuel); and
- Power conditioner (to convert from DC to AC and to regulate power production in accordance with load).

D.4.1.1 Applicability

Fuel cell installations are viewed as an extended generation strategy and thus are typically sited adjoining the end user. Currently, fuel cell installations remain small, just a few megawatts. The fuels potentially used by fuel cell installations are widely available.

D.4.1.2 Reliability

Power industry estimates for significant fuel cell technology implementation range from 5 to 10 years. As design improves with experience, fuel cells will provide high availability.

Fuel cells have demonstrated high reliability in pilot installation settings. Current manufacturing capacity of fuel cells is not yet established to the point where fuel cell installations are expected to address significant demand.

D.4.1.3 Environmental Impacts

Fuel cells can boast great potential for improving energy efficiency. Fuel cells generate significant quantities of waste heat that can be recovered in a cogeneration configuration. The proximity of fuel cells to the end user of generated power greatly reduces transmission losses.

Fuel cell environmental impacts directly related to operating the cell are minimal. By eliminating the combustion step of fossil fuel utilization, air emissions are virtually eliminated relative to conventional fuel-fired power generation. Indirect impacts may arise if a preliminary fuel processing step (e.g., coal gasification) is utilized to provide fuel for a fuel cell.

D.4.1.4 Economic Effects

The total capital requirement for developing a hypothetical fuel cell power plant is estimated to be prohibitively high. The size of fuel cell installations would require hundreds of fuel cell sites to provide capabilities in the range of a hundred MW or more. Fuel cells, individually, will

require maintenance, but will be too small to create a noticeable impact on local employment statistics.

D.4.2 Microturbines

Microturbines are a type of combustion turbine that is used for stationary energy generation applications. They are usually small units (common refrigerator size) with outputs that are very small, usually in the kilowatt range. Microturbines operate similar to a combustion turbine except on a much smaller scale. Generally, microturbines contain the following design features:

- Radial flow compressors;
- Low pressure ratios (single or possibly two stage compression);
- Minimal use of van or rotor cooling;
- Recuperation of exhaust heat for air preheating;
- Use of materials that are amenable to low cost production; and
- Very high rotational speeds on the primary output shaft (25,000 rpm or more).

Microturbines are capable of using many alternative/optional fuels including natural gas, diesel, ethanol, landfill gas, and other biomass-derived liquids and gases.

D.4.2.1 Applicability

Microturbines are well suited to meet intermediate, base load, peaking, or co-generation load needs. High kW output needs may not be feasible because existing power conditioning equipment does not allow easy interconnection between microturbine systems.

D.4.2.2 Applicability Reliability

Microturbines have relatively few moving parts and can operate continuously with little maintenance. Existing microturbine based power generation systems have demonstrated extremely high availability.

Microturbine systems can generally demonstrate high reliability (both the adequacy and security aspects). Natural gas-fired systems typically do no have alternative fuel options for backup. A reliable natural gas or other primary fuel source is required to have a reliable system.

D.4.2.3 Applicability Environmental Impacts

Environmental impacts in terms of energy efficiency (input fuel energy per kilowatt-hour produced) show a distinct disadvantage versus combined-cycle and coal-fired plants. Direct environmental impacts of operating a natural gas combustion microturbine include air emissions and waste heat discharge. Microturbines have manufacturer listed NOx levels from 9 to 50 ppm (typical generator natural gas combustion sources range from 45-200 ppm NOx).

D.4.2.4 Applicability Economic Effects

The total capital requirement for a microturbine power plant varies significantly, making it important to evaluate specific proposals before making economic conclusions. However, at this time large-scale implementation of this resource does not appear to be feasible.

D.4.3 Energy Storage

The application of energy storage technologies is best suited to peaking power needs since it presumes that there is excess or underutilized generating capacity at some point during which energy can be stored and released at a later point in time. Energy storage technologies have long been considered as a means of leveling the load on existing generating plants, thus allowing them to operate closer to their peak efficiencies. Energy storage is not well suited for meeting base load energy needs and must be combined with other energy resources to address reliability issues. Four storage technologies are discussed here - battery energy storage systems (BESS), compressed air energy storage (CAES), pumped storage hydroelectric, and flywheel energy storage.

Portions of the following discussion are based on information contained in the U.S. DOE/EPRI topical report on renewable energy technologies.[4]

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[4] U.S. DOE and EPRI. December 1997. "Renewable Energy Technology Characterizations", EPRI Topical Report TR-109496, www.eren.doe.gov/utilities/techchar.htm.

D.4.3.1 Battery Energy Storage System (BESS)

There are currently a wide variety of types of batteries available for use in energy storage applications. In a chemical battery, charging causes reactions in electrochemical compounds to store energy charged to the battery in a chemical form. When a load is applied to the battery, reverse chemical reactions allow the energy to be drawn from the battery. Commercially available batteries range in size from kilowatts to modular configurations of several megawatts.

D.4.3.2 Compressed Air Energy Storage (CAES)

CAES plants are designed to use off-peak energy from existing power plants to compress air and store it in air-tight underground caverns. When called upon, the air is released, heated, and expanded through a gas turbine to recover the energy. Although manufacturers offer equipment to construct CAES systems ranging up to 350 MW, to date only a 110 MW plant has been constructed in Alabama. The Electric Power Research Institute (EPRI) has estimated that more than 85 percent of the United States may have geological characteristics that would allow for CAES construction.

D.4.3.3 Pumped Storage Hydroelectric

Pumped storage hydroelectric plants pump the water resource, usually through a reversible turbine, from a lower reservoir to an upper reservoir. While pumped storage facilities are net energy consumers, they are valued by a utility because they can be rapidly brought on-line to operate in a peak power production mode. The pumping to replenish the upper reservoir is performed during off-peak hours when electricity costs are lowest. This process benefits the utility by increasing the load factor and reducing the cycling of its base load units. In most cases, pumped storage plants run a full cycle every 24 hours.

D.4.3.4 Flywheel Energy Storage

The concept behind this technology is to store energy in a spinning flywheel. An integral motor/generator is connected to the flywheel and can be used to either charge energy to the flywheel or extract energy from it. This technology has been applied to mechanical systems and is now receiving attention towards applying it to electrical systems. Commercially available flywheels constructed of steel are limited in size due to the potential for catastrophic failure. Advanced composite wheels have been designed but are not yet commercially available. Small demonstration systems, rated in the kilowatt range, have been constructed. Large-scale application of the technology has not been demonstrated.

D.4.4 Applicability

Energy storage projects require an energy producer with excess or underutilized generating capacity to charge the storage system. Where this excess capacity exists, energy storage

technologies are a means of leveling the load on existing generating plants thus allowing them to operate closer to their peak efficiencies. However, energy storage technologies do not meet intermediate or base load energy needs well.

D.4.5 Reliability

By their nature, energy storage systems have high availability so that power may be readily extracted and used. These systems would typically back up less reliable parts of the overall electric supply system and are best suited for peaking power needs.

Implementation times for the energy storage technologies discussed here would be variable due to the differences in issues between them. Small, disperse battery and flywheel systems could likely be installed within months, whereas CAES and pumped storage hydro facilities may require years of development effort likely involving contentious approval processes.

D.4.6 Environmental Effects

Quantitative values for efficiency of each system have not been identified. A feature of all storage systems is that less energy will be extracted than was originally stored. The process of storage requires an energy expenditure that cannot be recovered.

None of the four systems discussed here will directly release air pollutant emissions in significant amounts. Pumped storage hydro development will have impacts similar to any hydroelectric project development. Substantial areas of land and habitat may be lost due to hydro development. None of the technologies discussed here would discharge significant quantities of wastewater or noise.

D.4.7 Economic Effects

The capital costs for constructing an energy storage facility are variable and dependent on technology selection. However, as noted previously, energy storage projects require an energy producer to charge the storage system. The costs for energy storage typically assume that underutilized energy production facilities exist. Operating costs are primarily dependent upon the operating costs associated with the original energy source.

The economic benefits derived from development of energy storage projects may be limited to minor increases in employment levels and property tax benefits.

D.5 Summary of Developing Technologies

None of the developing technologies pass the initial screening as being viable for current implementation to meet our need. However, we will continue to monitor technology development and identify opportunities for utilizing emerging technologies.

Appendix E: Power Uprates Approved by the Nuclear Regulatory Commission (NRC)

E.1 Power Uprates Experience

E.1.1 Power Uprate Approved Applications:

- Calvert Cliffs, Units 1 and 2
- Millstone, Unit 2
- H.B. Robinson Nuclear Plant[1]
- Fort Calhoun Station
- St. Lucie, Units 1 and 2
- Duane Arnold[2]
- Salem, Units 1[3] and 2
- North Anna, Units 1 and 2
- Callaway
- Three Mile Island, Unit 1
- Fermi, Unit 2
- Vogtle, Units 1 and 2
- Wolf Creek
- Susquehanna, Units 1 and 2[4]
- Peach Bottom, Units 2 and 3[5]
- Limerick, Units 1 and 2
- Nine Mile Point, Unit 2
- Washington Nuclear Plant, Unit 2
- Surry, Units 1 and 2
- Hatch, Units 1 and 2 [6]
- V.C. Summer Nuclear Station
- Palo Verde Units 1 thru 3[7]
- Turkey Point Nuclear Plant, Units 3 and 4
- Brunswick, Units 1 and 2[8]
- James A FitzPatrick
- Farley, Units 1 and 2

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[1] Approval for 4.5% in 1979 and 1.7% in 2002.

[2] Approval received for 4.1% uprate in 1985 and 15.3% in 2001.

[3] Unit 1 was approved for a 2% uprate in 1986 and 1.4% in 2001.

[4] Two different applications in 1994, 1995 for Units 2 and 1 respectively and then in 2001. The first request was for a 4.5 % uprate and the second for a 1.4% uprate.

[5] Approval was granted in 1994 for 5% at Unit 2 and in 1995 for Unit 3. Both Units were also approved for 1.62% in\ 2002.

[6] Three applications: 1995 (5%), 1998 (8%), 2003 (1.5%).

[7] All Units approved at 2% in 1996 and Unit 2 at 2.9% in 2003 and Units 1 and 3 for 2.9% in 2005.

[8] Approval for 5% in 1996 and 15% in 2002.

- Browns Ferry, Units 1, 2 and 3
- Monticello
- Comanche Peak, Units 1 and 2[9]
- LaSalle, Units 1 and 2
- Perry
- River Bend[10]
- Diablo Canyon, Unit 1
- Watts Bar
- Byron, Units 1 and 2
- Braidwood, Units 1 and 2
- San Onofre, Units 2 and 3
- Hope Creek
- Beaver Valley, Units 1 and 2[11]
- Shearon Harris
- Dresden, Units 2 and 3
- Quad Cities, Units 1 and 2
- Waterford[12]
- Clinton
- South Texas, Units 1 and 2
- ANO-2
- Grand Gulf Nuclear Station
- Sequoyah, Units 1 and 2
- Indian Point, Units 2 and 3[13]
- Crystal River Nuclear Generating Plant, Unit 3
- Point Beach, Units 1 and 2
- D.C. Cook, Units 1 and 2
- Kewaunee Power Generating Station[14]
- Pilgrim
- Palisades
- Seabrook[15]
- Vermont Yankee
- Ginna

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[9] Unit 2 received approval for a 1% uprate in 1999 and approval for 0.4% in 2001.

[10] Approved for 5% in 2000 and 1.7%in 2003.

[11] Approved for 1.4% in 2001 and 8% in 2006.

[12] Unit 3 1.5% in 2002 and all units for 8% in 2005.

[13] Approvals for 1.4% for Units 3 and 2 in 2002 and 2003, respectively and 3.26% in 2004 and 2005, respectively

[14] Approved for 1.4% in 2003 and 6% in 2004.

[15] Approved for 5.2% in 2005 and 1.7% in 2006.