Minnkota Power Cooperative, Inc.

– and –

Northern Municipal Power Agency

2006 Integrated Resource Plan

2006 – 2020

Submitted to the

Western Area Power Administration

– and the –

Minnesota Public Utilities Commission

Minnkota Power
MPC COOPERATIVE, INC.
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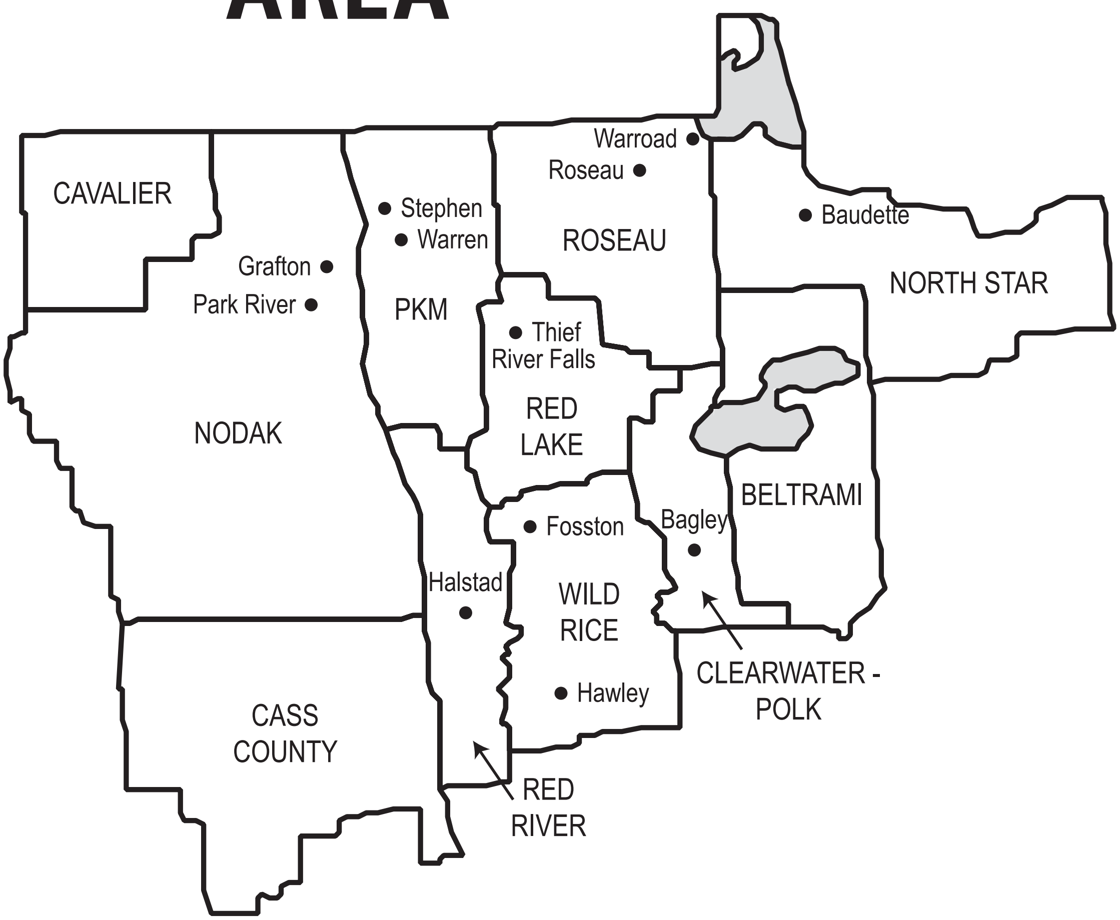
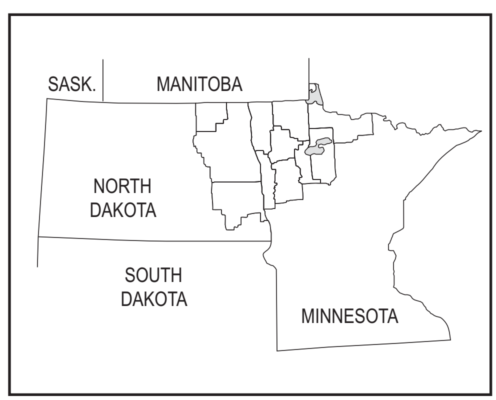
Northern Municipal Power Agency

SERVICE AREA





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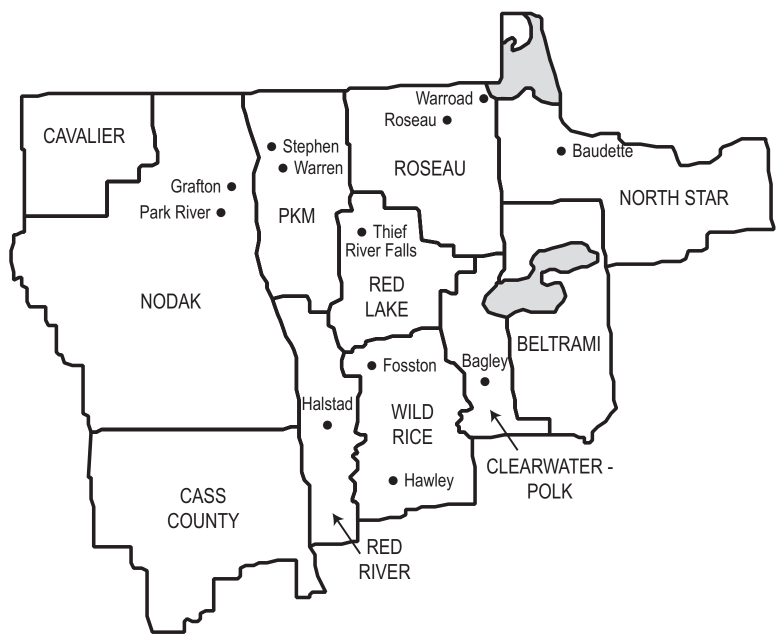
SECTION 1
Introduction

1.1 Minnkota Power Cooperative, Inc.

Minnkota Power Cooperative, Inc. (Minnkota) is a wholesale electric generation and transmission cooperative incorporated on March 28, 1940, and headquartered in Grand Forks, North Dakota. Minnkota provides, on a nonprofit basis, wholesale electric service to 11 retail distribution cooperatives, which are the members and owners of Minnkota. Minnkota is also associated with the Northern Municipal Power Agency (NMPA), which is a municipal power agency serving 12 municipals within its service territory.



The member-owner distribution cooperative systems (member systems) are cooperative associations that provide retail electric service to their own member consumers. In general, the membership of the member systems consists of residential, commercial and industrial consumers within a contiguous geographic area.

The member systems' service areas, which encompass 34,500 square miles, are located in northwestern Minnesota and the eastern third of North Dakota and contain an aggregate population of approximately 300,000 people. The member systems serve approximately 125,000 customers.

The primary function of the member systems is to provide the total electrical requirements of their own member-owner consumers through wholesale purchases of capacity and energy from Minnkota and to deliver this capacity and energy through their electrical distribution facilities.

1.2 Member Systems' Wholesale Power Contracts

Minnkota has entered into a Wholesale Power Contract with each of the 11 member systems that is in force until December 31, 2040, and thereafter until terminated with six months' written notice of either party. These Wholesale Power Contracts provide that Minnkota shall sell and deliver to each of the member systems, and that the member systems shall purchase and receive from Minnkota, all of the members' electrical capacity and energy requirements.

Each member system is required to compensate Minnkota for capacity and energy furnished under the Wholesale Power Contract in accordance with the rates set forth in the Wholesale Power Rate Schedule. Minnkota reviews its Wholesale Power Rate Schedule at such intervals as it deems appropriate and is required to do so at least once every year. The rates will be revised as necessary so that the revenues derived thereunder will be sufficient, together with its revenue from all other sources, to pay all operating and maintenance costs, taxes, the cost of purchased power, the cost of transmission services, and principal and interest on all indebtedness, and to provide for the establishment and maintenance of reasonable reserves. Any excess revenue is returned to the members as capital credits.

The Wholesale Power Rate Schedule is structured so as to enable Minnkota to comply with all requirements under its Mortgage, dated as of September 26, 1996, as supplemented, between Minnkota and the United States acting through the Administrator of the Rural Utilities Service (RUS), formerly the Rural Electrification Administration (REA). The Wholesale Power Rate Schedule is subject to the approval of the RUS.

1.3 Organizational Structure

Each member system is governed by a Board of Directors who are elected from the membership of that system. Minnkota is governed by a Board of Directors consisting of one director from each of the 11 member systems. Directors are elected annually at delegate meetings of the member systems. Meetings of the Minnkota Board are held monthly. The officers are elected from the members of the Board of Directors by the Board members. The officers are the Chairman, Vice Chairman and Secretary-Treasurer. The Minnkota Board also appoints an Assistant Secretary. The officers also constitute the executive committee, which makes recommendations to the Board.

1.4 Northern Municipal Power Agency

The Northern Municipal Power Agency (NMPA) consists of 12 municipal utilities, 10 in northwestern Minnesota and two in eastern North Dakota. The 12 municipal utilities serve the electrical requirements of approximately 15,000 customers.

NMPA was founded in 1976 and is headquartered in Thief River Falls, Minnesota. The Board of Directors of NMPA consists of one representative from each of the 12 participants. NMPA is a Class B member of Minnkota and selects a nonvoting member to attend meetings of Minnkota's Board of Directors.

NMPA owns a 30 percent share of the Coyote generating plant, a 427 MW facility located near Beulah, N.D. NMPA also owns a 15 percent undivided interest in Minnkota's transmission system. Minnkota is the operating agent for NMPA.

1.5 Minnkota Membership

The 11 member systems are Class A members of Minnkota. NMPA is a Class B member of Minnkota. In addition, there are several other Class B members and Class C members, all of which contract for short-term power purchases from Minnkota and are entitled to have delegates attend Minnkota membership meetings.

1.6 Joint System Concept and Relationship

Minnkota and NMPA effectively form a Joint System. This is by virtue of operating agreements and joint ownership of transmission facilities. Additionally, Minnkota's generation, NMPA's generation, Minnkota's Western Area Power Administration (WAPA) allocation, and the NMPA WAPA allocations are collectively utilized to serve the Joint System capacity and energy requirements. Also, both the member systems of Minnkota and the member municipals of NMPA purchase their total electric capacity and energy requirements under identical Wholesale Power Rate Schedules.

1.7 Management and Administration

Minnkota is operated by approximately 320 full-time employees under the direction of the President & Chief Executive Officer, who is appointed by and is responsible to the Board and who is not eligible to serve as a director of Minnkota. Approximately 168 employees operate out of the general headquarters in Grand Forks, N.D. Approximately 152 are located at the Milton R. Young Station located near Center, N.D.

1.8 Minnkota Membership in the Mid-Continent Area Power Pool

The Mid-Continent Area Power Pool (MAPP) is a voluntary association of approximately 90 members consisting of investor-owned utilities, public power utilities, cooperatives and power marketers serving end-use customers in Minnesota, North Dakota, South Dakota, Nebraska, Iowa, Wisconsin, Montana, and the Canadian provinces of Manitoba and Saskatchewan. Minnkota has been a member of MAPP since its inception in 1972.

MAPP members work together voluntarily to protect the reliability, assure the adequacy and reduce the cost of electricity. The common goal is to plan and operate generation and transmission facilities for the mutual benefit of all MAPP members.

MAPP has been recognized as one of the more progressive power pools in assisting members in planning facilities and in operating interconnected systems. The cooperation among members is one of the main contributing factors in maintaining economical electricity costs and adequate reliability for the end-use consumers.

Minnkota and the other members benefit greatly from their association with MAPP. These benefits include increased electric reliability at lower cost for end-use consumers through the sharing of generation reserves. If each member were responsible for its own generation reserves, there would be a significant amount of additional capacity required by all utilities. However, MAPP members can call on the other members for assistance during emergencies and thereby reduce the amount of reserve generation that it needs to provide reliable service to its customers. Through the sharing of reserves, each MAPP member is required to carry only a 15 percent reserve margin, based on its annual peak demand.

Another area in which Minnkota benefits from participating in MAPP is in the purchase and sale of energy from other members. MAPP Service Schedules are organized to promote cost-effective transactions. Minnkota has made extensive use of these Service Schedules in selling its surplus energy and in purchasing economical energy for its own end-use customers.

Neither the sharing of reserves nor the sale or purchase of energy would be possible without the interconnected transmission facilities and the cooperation among members. The cooperation and interconnection of members is a result of and will continue only as long as an organization such as MAPP provides the framework for integrated and coordinated planning and operating of interconnected facilities.

1.9 Market Participant Membership in the Midwest Independent System Operator's (MISO) Energy Market

Minnkota is a market participant in the Midwest Independent System Operator's (MISO) energy market. This allows Minnkota to purchase energy from or sell energy into the MISO energy market. This MISO market is another source for the Joint System's energy requirements. However, the energy purchased from the MISO market is significantly higher in cost than the energy produced from the Joint System's generation resources.

1.10 Mission Statement

The mission of Minnkota is to keep our electricity the best energy value in the region.

SECTION 2

Resource Plan Summary

2.1 Introduction

Minnkota Power Cooperative, Inc. (Minnkota) is a wholesale electric generation and transmission cooperative supplying the electrical requirements of 11 rural distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota is also associated with the Northern Municipal Power Agency (NMPA), a municipal power agency serving 12 municipals within the service area. Minnkota, through the member-owner distribution cooperatives (members) and the NMPA municipals, serves approximately 125,000 customers in a 34,500-square-mile territory.

Minnkota and NMPA have formed a Joint System and together submit this Integrated Resource Plan (IRP). This document has been prepared to fulfill the IRP requirements of the Western Area Power Administration (WAPA) and the Minnesota Public Utilities Commission.

The primary function of an IRP is to demonstrate how a utility plans to meet the electrical needs of its end-use consumers over the next 15 years. The resource plan includes the resource and demand side options that best fit the utility's forecasted energy requirements. Resource plans must consider how to maintain or improve electric service to customers, maintain low electric rates, minimize environmental impacts, and minimize the risk of adverse effects from financial, social and technological impacts.

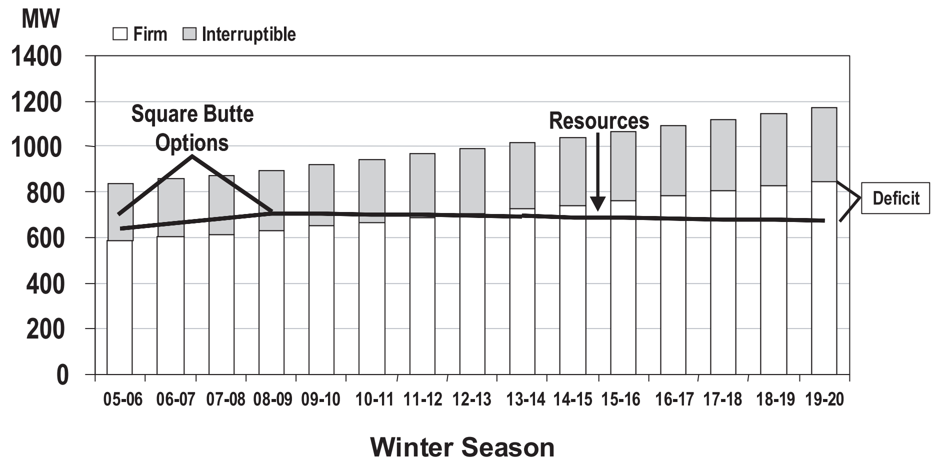
2.2 Load Forecasts

The median load forecast utilized in this IRP is the summation of Minnkota's 2005 Power Requirements Study forecast and a linear regression analysis of the individual NMPA municipals' historical energy requirements. A high growth energy forecast and a low growth energy forecast were derived from the median energy forecast. The high growth and low growth energy forecasts were developed from sensitivity analyses that estimated the effects that extremely harsh and mild weather conditions would have on energy requirements. Winter and summer peak demands were developed for the low, median and high growth forecasts of the energy projections.

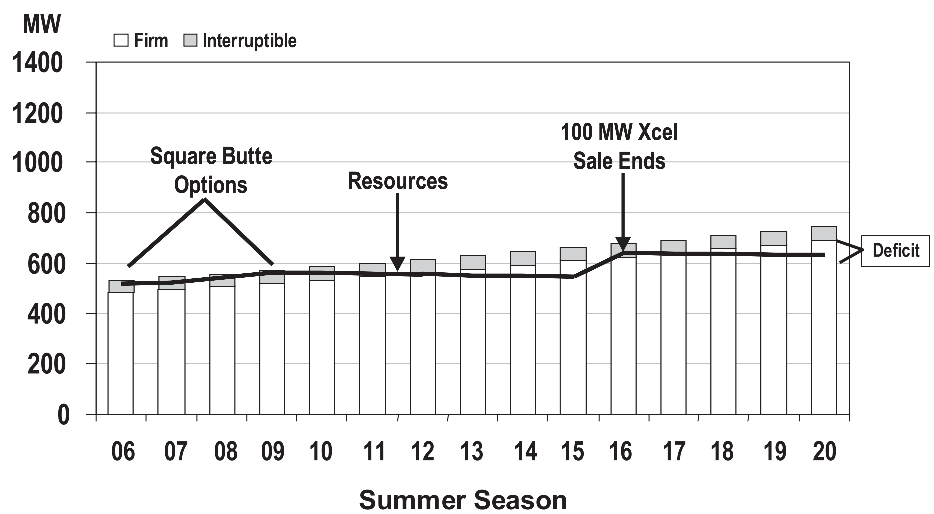
The Joint System energy requirements are forecasted to increase at a rate of 2.4 percent per year for the next 15 years. The summer and winter peak demands are also forecasted to increase at a rate of 2.4 percent per year.

The following charts display the winter and summer peak demands, separated into the firm and interruptible components. Also shown in these charts are the winter and summer capacity resources, represented as a line. Capacity resources are the Joint System generation plants, WAPA allocations, capacity purchases and sales, minus reserve obligations.

Joint System
Winter Capacity vs. Load



Joint System
Summer Capacity vs. Load



2.3 Load and Capability Report

As part of the responsibilities of belonging to MAPP, Minnkota is required to maintain, either by owning generation or by capacity purchases, sufficient generation capacity to serve 115 percent of its annual peak demand. The additional 15 percent is required by MAPP for reserves, which may be needed to serve unexpected load growth or system emergencies. Each member of MAPP has a similar obligation to carry reserves.

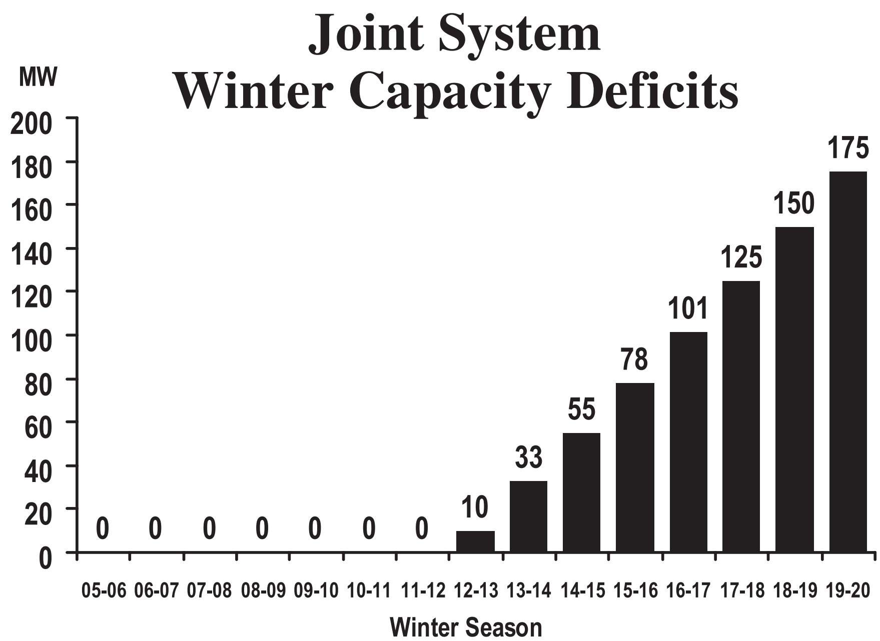
However, if a MAPP utility's actual load plus reserve obligation exceeds its net generation capability, then it is required to purchase generation capacity from other MAPP members. The purchase is usually at a much higher rate than if the utility had made its own arrangements prior to becoming deficit. The reason for the stiff penalty is to ensure that adequate and timely generation capacity additions materialize to maintain a high degree of reliability for the end-use customers.

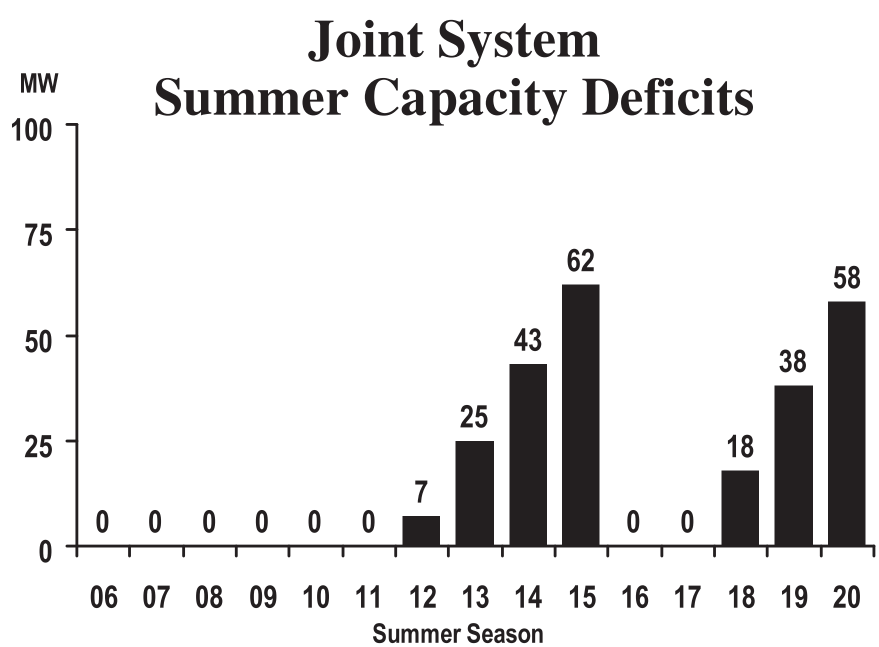
MAPP developed a Load and Capability (L&C) Report to help its members plan their future capacity requirements. The L&C Report is a forecast of the utility's generation, load and reserve requirements. This Report takes into account not only the utility's load and generation, but also sales and purchases. Schedule L purchases are also taken into account in this Report. It is an important planning tool for MAPP utilities, since it aids forecasting the amount of future generation capacity that will be required by taking into account the needed planning reserves.

The Joint System does not complete a L&C Report; only Minnkota does. However, Minnkota does have the responsibility of providing for the future load growth of the NMPA municipals, and therefore must take into account the reserve capacity obligation as well as the load growth of the NMPA. This is done by completing a L&C Report for the Joint System. The Joint System L&C Report is used for internal planning purposes.

The L&C Reports highlight what the expected surplus/deficit situation of the Joint System will be in the future. The amounts of capacity that the Joint System will be deficit in the future will determine, to a great extent, generation expansion planning.

The following charts display the expected generation capacity deficits that the Joint System is forecasted to experience in the next 15 years given the existing resources and forecasted load growth:





In order to insulate its end-use customers from the high cost and volatility of the energy market, the Joint System is evaluating the options it has available to mitigate these potentially devastating impacts of relying on the market to supply significant amounts of its customers' energy requirements.

The Joint System has begun to evaluate its generation resource expansion opportunities, as well as its renewable resource requirements. These efforts are more fully explained in later sections of this report.

At this time, no decision has been made regarding any generation capacity expansion plans.

2.4 Energy Considerations

In addition to generation capacity deficits, the amount of energy that the Joint System needs to procure from resources not under its control is another important factor in determining long-term generation expansion planning.

The Joint System has a number of generation resources that are comparatively low cost. The Young 1, Young 2 and Coyote generating units are all baseload, low-cost energy resources. In addition, the NMPA WAPA firm power allocation and Minnkota's firm power allocation are also low-cost energy resources. However, the remaining generating resources are mostly old diesel units and are high cost.

However, the Joint System's energy requirements significantly exceed the amounts of energy that its economical generation can produce. This situation only exacerbates with load growth. The following table documents, by winter and summer seasons, the amounts of energy the Joint System requires over and above what its economical units can supply:

Winter Season Statistics

Season	Joint System Energy Requirements MWh	Energy Requirements Above Economical Generation Resources MWh	Percent of Energy Requirements Above Economical Generation Resources %
2005-06	2,599,681	145,842	5.610
2006-07	2,677,704	142,361	5.317
2007-08	2,725,702	126,353	4.636
2008-09	2,793,189	119,559	4.280
2009-10	2,865,963	129,462	4.517
2010-11	2,936,474	161,437	5.498
2011-12	3,010,862	199,066	6.612

2012-13	3,086,197	241,887	7.838
2013-14	3,163,603	290,967	9.197
2014-15	3,239,512	342,686	10.578
2015-16	3,317,260	359,944	10.851
2016-17	3,396,842	416,066	12.249
2017-18	3,478,397	475,927	13.682
2018-19	3,561,887	539,387	15.143
2019-20	3,647,298	606,925	16.640

Summer Season Statistics

Season	Joint System Energy Requirements MWh	Energy Requirements Above Economical Generation Resources MWh	Percent of Energy Requirements Above Economical Generation Resources %
2006	1,345,815	13,917	1.034
2007	1,395,486	10,432	0.748
2008	1,420,501	5,891	0.415
2009	1,455,644	3,791	0.260
2010	1,493,594	7,805	0.523
2011	1,530,359	13,694	0.895
2012	1,569,142	22,695	1.446
2013	1,608,391	34,714	2.158
2014	1,648,674	49,354	2.994
2015	1,688,232	65,213	3.863
2016	1,728,704	4,859	0.281
2017	1,770,163	9,332	0.527
2018	1,812,649	16,166	0.892
2019	1,856,183	26,212	1.412
2020	1,900,702	39,615	2.084

The danger in having to depend on the energy market to supply a significant amount of the Joint System's energy requirements, rather than from its own generation resources, is that the market can be extremely volatile and quite expensive.

There is another inherent danger in relying on the energy market for significant amounts of energy. The inherent danger is that even though the energy may be available from the market, it may not be deliverable because of transmission limitations. There is no guarantee that the transmission required to transport energy from the market to the Joint System will be available when the energy is needed.

2.5 Summary

Minnkota's load forecast and the resulting analysis for the Joint System energy requirements strongly indicates the need for future generation additions. From both a load and capability analysis (which determines the need for addition capacity needs) and from an energy requirements analysis (which determines the need for additional energy sources), it was concluded that the Joint System should investigate the feasibility of adding a third coal-fired generating plant at the existing Milton R. Young generating station, located near Center, N.D.

The decision to investigate the addition of a third unit was driven by the fact that future energy requirements were of the magnitude that the most reliable, secure and cost-effective long-term solution would be the addition of baseload generation capacity.

Based upon the results of the feasibility study, a 400-600 MW coal-fired unit is the most economical generation addition from both an RUS and IOU financing perspective and from a long-term levelized busbar cost projection.

The levelized busbar cost projection is slightly lower than other coal-fired alternatives and is significantly lower than the baseload natural gas combined cycle alternative. The combined cycle combustion turbine utilized as a peaking unit and coupled with off-peak power purchases also had significantly higher busbar costs than the recommended alternative.

Based upon the results of the feasibility study, it has been decided to continue to explore more fully the addition of a third unit at the Milton R. Young Station. At this point in time the Joint System has not committed to constructing a third unit, only to more fully explore all the ramifications of such a decision.

If a 400-600 MW unit were constructed, Minnkota would not be the only owner. At this time it is envisioned that Minnkota's share of the new unit would be approximately 150 MW. The remaining portion of the unit would be owned by other area utilities.

SECTION 3

Load Management Program

3.1 Historical Perspective

Beginning with relatively modest efforts in 1973, Minnkota and the member systems have assembled a comprehensive and effective Load Management (LM) Program. Today, approximately 51,000 end-use consumers are an integral part of this important program.

Minnkota's LM Program started in 1973 with dual heating systems as the main focus of the effort. By 1974 national energy shortages, combined with high inflation, helped shape Minnkota's philosophy on LM. The increased demand for electric generation capacity needed to be addressed. The traditional course of action would have been to add more generating plants to meet the increased energy requirements. However, because of the high cost of adding additional generation capacity, considerable risk would be associated with any generation capacity expansion plans. After much thought and analysis, Minnkota management decided to embark on a LM Program to alleviate the impending shortages in generation capacity.

A LM Program was an attractive option for many reasons:

1. The rapid escalation in the cost of building new baseload generation led Minnkota to search for less costly solutions.
2. The possible financing, environmental, legal and siting problems were significant unknown obstacles to constructing new generation.
3. The nature of Minnkota's native load, with its emphasis on electric heating, caused a winter peaking situation. This situation resulted in a poor annual load factor, but also lent itself well to load management implementation.
4. The LM Program offered residential and commercial customers a cost-effective option for meeting their space heating requirements.

In 1975, Minnkota's overall LM strategy was finalized. The foundation for this successful program hinged on three interdependent areas: rate design, control methodology and controllable electric loads.

3.2 Wholesale Rate Design

A progressive wholesale power rate design was needed to convey a message to the member systems and their end-use customers. The message Minnkota wanted to communicate was that demand side management was an important tool that would delay or eliminate the need for costly new generation plants. The rate schedule that was developed to communicate this message placed a significant emphasis on peak demand by instituting a high demand charge. Since annual peak demand determines a sizable portion of Minnkota's power supply obligations and therefore its expenses, the rate schedule included a 100 percent ratchet on peak demand. This 100 percent ratchet means that the peak demand established on a member system coincidental with Minnkota's billing peak was billed at that amount throughout the year. This concept represented a key factor in the development of a wholesale power rate structure that incorporated proper emphasis for demand side management. The following table illustrates the different components of the 1977 Wholesale Power Rate Schedule.

1977 Wholesale Power Rate Schedule

Base Demand Charge	$25.20/kW/year
Excess/Growth Demand Charge *	$48.00/kW/year
Energy Charge	5.5 mills/kWh
Substation Charge	$4,800/substation/year

* Demand in excess of a predetermined value

In the last few years Minnkota has modified its Wholesale Power Rate Schedule to better reflect its expenses in the pertinent rate components. Because the market value in MAPP for summer season generation capacity had increased considerably, Minnkota instituted a summer demand charge that is applied to the highest summer billing peaks. In addition to the summer demand charge, a transmission charge was added to incorporate the expense of transmission service. The transmission charge is a two-tier rate, meaning it has both an energy component and a demand component. The transmission energy rate is applied to all energy sold to the member systems. The transmission demand rate is applied to the winter metered demand value. The winter demand rate is applied to the winter billing demand value and the summer demand rate is applied to the summer billing demand value.

The winter billing demand, the summer billing demand and the transmission demand charge all carry a 100 percent ratchet, meaning that those charges are applied for 12 months. This aspect of the wholesale power rate is a potent incentive to reduce winter and summer peak demands by participating in the LM Program. The following table illustrates the different components of the 2005 Wholesale Power Rate Schedule.

2005 Wholesale Power Rate Schedule

Energy Charge	18.37 mills/kWh
Winter Demand	$44.04/kW/year
Summer Demand	$44.04/kW/year
Transmission Charge	
Demand	$24.48/kW/year
Energy	2.45 mills/kWh
Substation	
Fixed	$14,700/substation/year
Variable	$1.32/kW/year

3.3 Load Management Control Methodology

A control system was needed that would enable Minnkota to continuously monitor and control the coincidental energy requirements of its member systems. This need resulted in the philosophy of central control, which was imperative in gaining the full benefits of the LM Program.

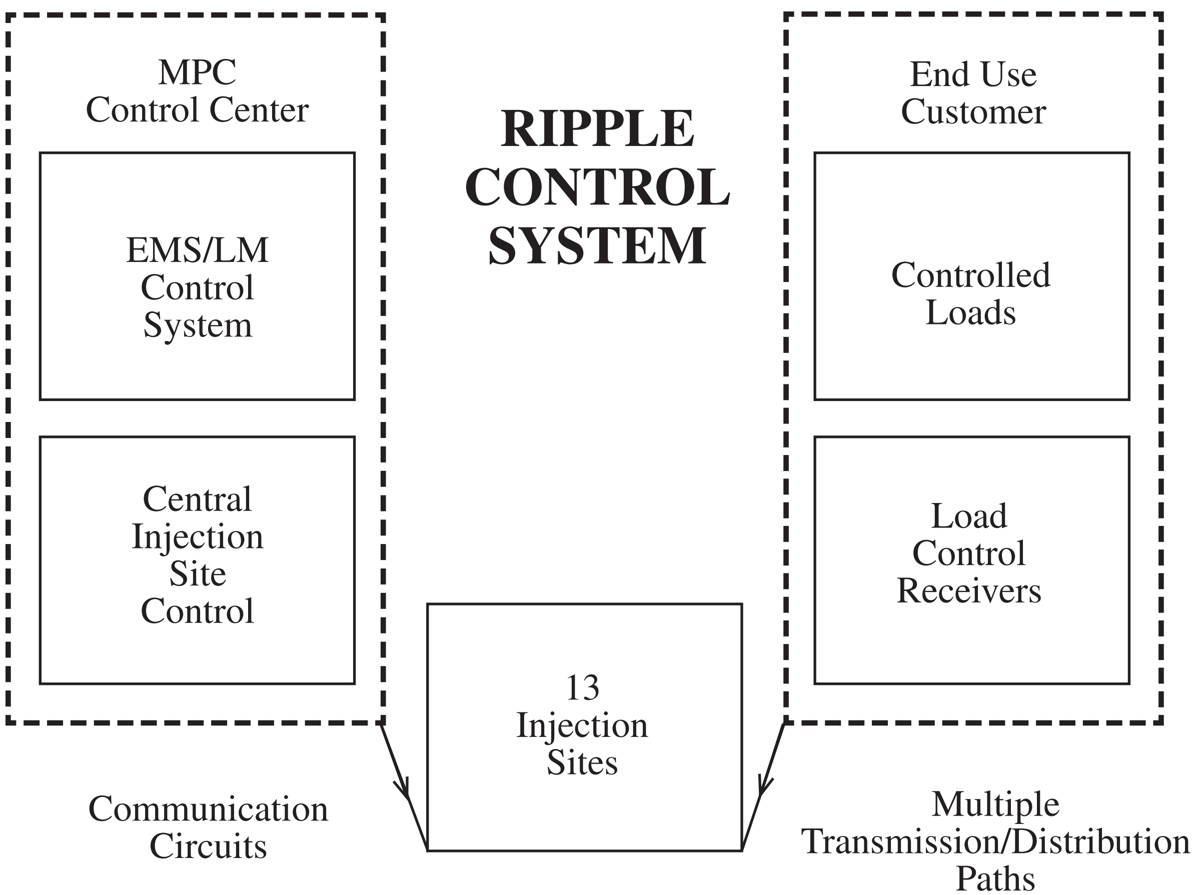
Research was carried out in 1974 and 1975 to determine the optimum method of controlling loads from a centralized location. Radio, carrier and ripple systems were all studied to evaluate their suitability to fulfill Minnkota's control strategy requirements. Radio control was discarded because of limited operating flexibility and the requirement of 30 transmitter sites to cover the entire service territory. Carrier was discounted because it lacked a proven track record and would require over 130 control sites, one at each of the then-existing distribution substations.

Ripple control was selected because of favorable economic costs, readily available, proven reliability, flexibility and the ability to meet the unique requirements of Minnkota's LM Program. The decision to buy a Landis & Gyr ripple control system for the LM Program was made in March 1976. This decision was subsequently approved and funded by the Rural Electrification Administration. Minnkota's service territory was initially covered by 12 ripple signal injection sites.

3.4 Load Management Control System

Minnkota's LM control system has been in operation since the fall of 1977. Since that time, it has evolved from a simple "stand-alone" manual system to a complex computer-based system; one that has been integrated into the practices and procedures of conventional power system planning and operations.

A Landis & Gyr 220 Hertz Ripple Control System was chosen on the basis of its proven reliability. To date, 51,000 ripple control receivers have been installed at end-use customer sites. All 51,000 receivers are directly controlled from the Minnkota Control Center located in Grand Forks, N.D. The Ripple Control System has been integrated with the Supervisory Control and Data Acquisition (SCADA) System. This integration was done to allow Control Center personnel to better predict and monitor the effects of control actions on power system operations. A block diagram of the LM equipment is shown in the following chart.



The Landis & Gyr central control unit in Grand Forks is linked by microwave to 13 injection sites (nine 69 kV and four 115 kV) located at transmission substations dispersed throughout the 34,500-square-mile service territory. These 13 injection sites are used simultaneously and can selectively control approximately 100,835 different loads that are connected to the 51,000 receivers. Because all 13 injection sites can be utilized simultaneously, it is possible to shed all interruptible load in three minutes (two-thirds can be shed in 25 seconds). Since latching relays are utilized in the receivers, all loads, when controlled, will remain in the off until an "ON" signal is sent by the Minnkota Control Center. This fact, coupled with the relatively few receiver misoperations, makes the Ripple Control System very dependable.

3.5 Winter Season Interruptible Loads

Three broad categories of load types were established into which a large variety of interruptible loads can be placed. The different categories of load groups are based on amount of time the controllable loads could be interrupted. The three different categories are described below.

Load Group I	Short-Term: Loads that can be interrupted up to four continuous hours at a time, up to eight hours per day. Water heaters are the most predominant loads in this category.
Load Group II	Medium-Term: Loads that can be interrupted up to 16 continuous hours per day. Typical loads in this category are thermal storage heaters.
Load Group III	Long-Term: Loads that can be interrupted for an indefinite time period. Dual fuel heating systems are the primary loads in this category. Electricity is the primary heating source with oil or propane as the backup fuel source.

3.6 MAPP Service Schedule L

Minnkota realized in 1980 that as more interruptible loads were added to each of the three load categories, certain constraints would eventually limit the effectiveness of the LM Program. For example, water heaters and other storage loads could only be interrupted for limited amounts of time. Normally the diversity of water heaters is approximately 25 percent. What a diversity factor of 25 percent means is that at any moment, only one out of four water heaters is actually heating water. The other three water heaters are not actively heating water at that moment, only storing previously heated water, until the supply of hot water is depleted and the temperature of the incoming water has to be raised.

The diversity of the different categories of interruptible load has to be taken into account in operations of any LM Program. What this means for Minnkota in this particular situation is that whenever water heaters are to be controlled, only 25 percent of the nameplate amount of water heaters will be shed when the ripple signal is sent. This is an important operational restriction that needs to be taken into consideration since Minnkota needs to be at or below its generation capacity level.

The other significant aspect of storage loads, such as water heaters, is that after a certain amount of interruption time, the diversity factor for these loads changes drastically. For example, when water heaters have been interrupted for four hours, the diversity factor will be approximately one. This means that instead of the situation when these loads are initially interrupted and only one of four was heating, after four hours on interruption, almost all of the water heaters will be heating water. The diversity factor changes because after four hours of interruption, most water heaters have been depleted of hot water due to showers, clothes washing, dish washing, etc. Therefore, care has to be exercised whenever storage loads such as water heaters are restored, so that a peak demand is not created that will be greater than what the original peak would have been, absent any load interruption. Effectively, this requires that the hourly load curve have a valley between the peaks that is large enough to handle the “payback” of storage loads so that a higher peak load is not created when these loads are restored.

Another potential problem for the LM Program was dual heating loads. Initially, the goal was to provide 90 percent of the annual heating requirements electrically and the remaining 10 percent with an alternate fuel. However, as more and more dual heating loads were added to the LM Program, the greater the amount of interruption time resulted for each customer, since Minnkota would have to interrupt loads longer to maintain its peak at or below its generation capacity level. Considering the potential problems in the future with storage load and dual fuel heating loads, Minnkota staff recognized that continuing down the existing path would severely limit the usefulness of the LM Program.

3.7 MAPP Service Schedule L

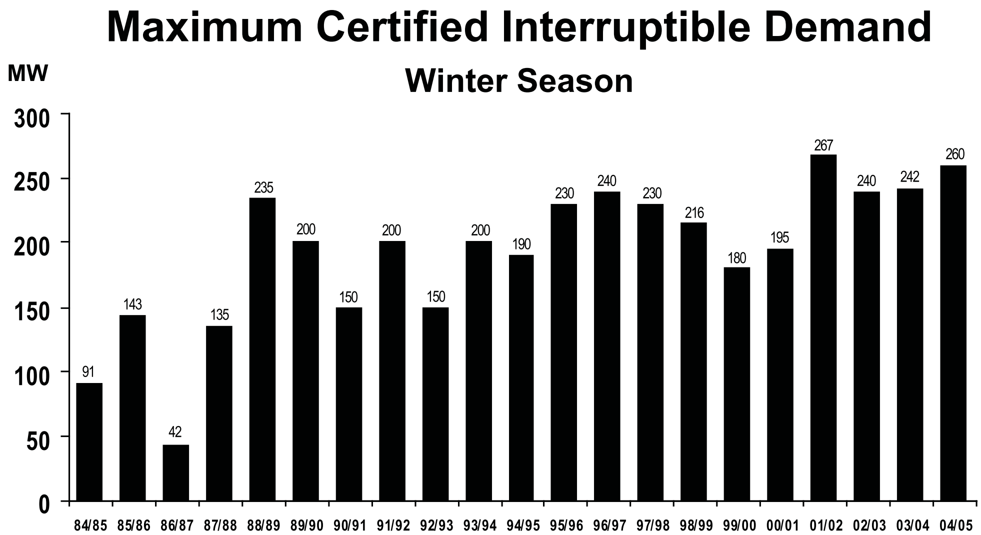
In October, 1980 Minnkota staff began discussions with MAPP staff about the requirements that MAPP utilities had for reporting interruptible load and the effects that such requirements had on LM Programs. The focus of these early discussions was on the following topics:

1. MAPP requirements mandated curtailment of interruptible loads whenever a utility's load exceeded its generation resources.
2. Dual fuel heating loads were forced to utilize high cost alternate fuel during this time, thereby increasing unnecessarily the end-use customer's heating expense.
3. Due to the diversity between the different MAPP members, surplus economical energy was available during the times Minnkota was forced to interrupt dual heating loads due to load levels approaching Minnkota's generation capacity limits. This happened because MAPP, as a whole, is summer peaking while Minnkota is winter peaking.
4. The net result was that MAPP had a reduced share of the end-use electric energy market, even though there was adequate economical electric energy available that could have been sold to Minnkota for its interruptible heating loads.

Minnkota's proposal to MAPP staff was to expand the tangible benefits of Minnkota's LM Program and other MAPP utilities load management programs by the addition of a new Service Schedule into the MAPP Market Protocols. There were two logical benefits for MAPP members from this addition. The first benefit was a new end-use market for surplus energy in MAPP. The second was the ability to interrupt directly controlled loads during generation emergencies. In effect, the interruptible loads would be utilized as generation reserves.

In October of 1983 MAPP adopted a new service schedule, named Service Schedule L, to increase its end-use electric market by allowing utilities to serve interruptible loads without incurring an increased generation reserve obligation. The generation reserve obligation, usually associated with serving load, was waived for those loads which were interruptible and for which Schedule L energy was purchased. Waiving the requirement to maintain generation reserves for interruptible load is a very significant part of the game plan to keep the cost of serving interruptible load as low as practical.

Certain requirements have to be followed by those utilities that purchase Schedule L energy. One of the requirements is that prior to the actual purchasing of Schedule L energy, a MAPP utility must demonstrate its ability to interrupt its interruptible loads for a four-hour period. Secondly, the MAPP utility has to demonstrate that it can maintain its system load at or below its capacity level for a 24-hour period during peak load conditions. These procedures are commonly referred to as the four hour and the 24-hour Certification of Interruptible Demand (CID). The following graph displays the maximum amounts of CID that has been approved by MAPP for the Joint System since the 1984-85 winter season.



Minnkota's load management system is very capable of meeting the CID requirements associated with utilizing Schedule L energy purchases and has done so for a number of years. Another provision within the Service Schedule L requirements allows utilities with mature load management systems that have a proven track record to waive some of the monthly certification requirements. Minnkota has applied for and been granted waivers for a number of years.

Service Schedule L is an important tool that Minnkota utilizes to maintain a cost-effective LM Program for its end-use customers. Since the upper Midwest is comprised of mostly utilities that are summer peaking and Minnkota's need for Schedule L energy is mainly in the winter for its dual heating loads, there should be ample Schedule L energy available for Minnkota to purchase. In the event that Schedule L energy is unavailable or priced too high, Minnkota has the option of interrupting the load and avoiding the need for the energy. Curtailing interruptible load is the most cost-effective method of dealing with the unavailable or high-cost Schedule L energy.

3.8 Winter Load Control History

After centralized load control equipment was installed in 1977, Minnkota has interrupted loads for a number of reasons. Predominately, loads were interrupted to either limit peak demand, determine member systems' billing demand or to avoid purchasing high-cost energy.

One of the obligations that Minnkota acquired by becoming a member of MAPP is the requirement to maintain sufficient generation capacity to cover its season peak demand plus 15 percent reserves. In Minnkota's case, the peak demand has always occurred in the winter season, due to the extensive heating loads on the electric system. From 1977 through 1984, Minnkota interrupted loads to maintain the winter peak demand within its existing generation capability. After 1984, when Schedule L became available, Minnkota interrupted load to fulfill Schedule L certification requirements, determine member systems' peak demand for billing purposes or to avoid purchasing high cost energy.

3.9 Interruptible Load Development

During the last 28 years, the member systems have developed a high degree of expertise in determining what end-use loads are adaptable to the LM Program, and which ones are not. For any end-use load to be successful in the LM Program, the consumer must be offered an incentive (through the retail electric rate) that is fair compensation for having the load interrupted. To work properly, the LM Program requires that the Wholesale Power Rate Schedule be fair and equitable for all the member systems and that the member systems have retail rate schedules which are fair, equitable and competitive.

Minnkota's and the member systems' philosophy is to develop interruptible loads in such a manner that the LM Program causes as little inconvenience as possible for the end-user. Interrupting load should be accomplished in a way such that the consumer experiences minimal inconvenience and yet be cost-effective for the end-user, the member systems and Minnkota.

Based on the last 28 years of operational experience with winter interruptible loads, the following is a forecast of the amount of demand relief that will be realized in future winter peak load periods.

Winter Season	Interruptible Load – MW
2006-07	257
2007-08	260
2008-09	265
2009-10	270
2010-11	275
2011-12	281
2012-13	286
2013-14	291
2014-15	297
2015-16	302

2016-17	307
2017-18	313
2018-19	318
2019-20	324

3.10 Summer Season Load Management

Since the mid-1990s summer season, generation capacity in MAPP has been increasing in value, due to load growth. At this time Minnkota was also experiencing load growth with regard to its summer season peak demand. Minnkota staff analyzed the implications of continued summer load growth and concluded that additional generation capacity would need to be acquired if the projected increases in summer peak demand were realized.

Discussions and meetings took place in 1994 with the member systems and the NMPA municipals to consider what could be instituted to slow down summer peak demand growth. One of the methods discussed was the extension of the existing LM Program into the summer season. The extension of the LM Program to include the summer season was deemed the least expensive way to manage the increase in the summer peak demands. During the summer of 1994 preparations were initiated to integrate summer season load management strategies and activities into the existing LM Program. Those preparations are discussed below.

First, a survey of the member systems and the NMPA municipals was completed in August of 1994 that provided an estimate of the amount and type of loads that could be utilized for summer load control. A total of 32,627 kW was identified as possible end-use customer loads that could be interrupted during the summer peak load situations.

The largest category of possible candidates consisted of loads that have diesel generator backup. The survey showed a total of 14,644 kW of generation already installed at customer sites. Most of these generators are already utilized for winter load control. For example, Marvin Windows, a manufacturing firm in Warroad, Minn., has 4,500 kW of diesel generation that is currently utilized for winter load management.

A residential load analysis was conducted during the summer of 1994. A number of recording devices were installed in a new housing subdivision of Grand Forks, which is served by one of the member systems. Air conditioning loads, temperatures, total residential loads and distribution feeder loadings were analyzed. The following observations were made after the collected data was analyzed.

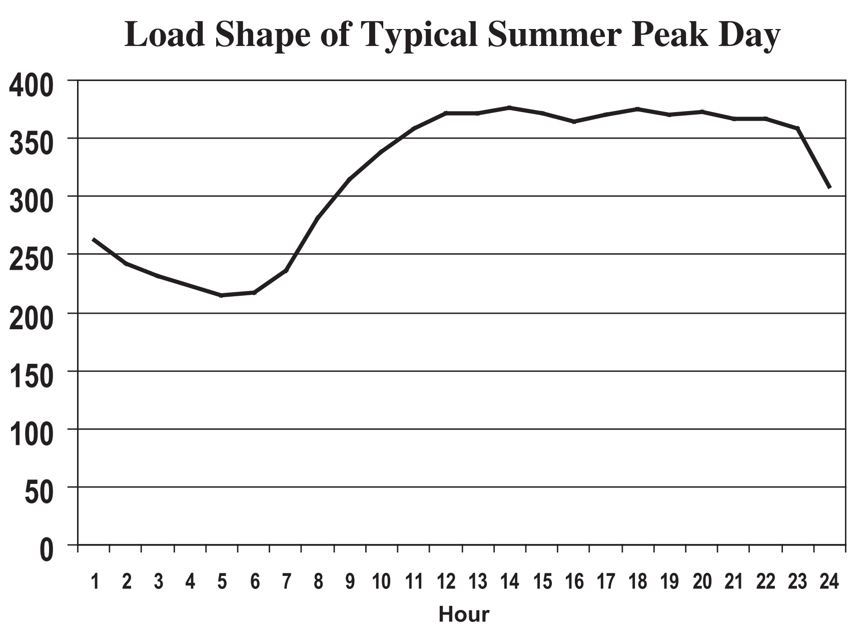
1. Individual residential peak loads, including air conditioning, varied from 0.1 kW to 14.0 kW.

2. On a system-wide basis, air conditioning loads averaged 1.0 kW per hour per air conditioner during moderately hot weather (91 degrees).
3. Individual residential central air conditioners can average 2.5 kW for five continuous hours during moderately hot weather.
4. That the air conditioners that are in use can vary considerable among end-use customers, but in moderately hot weather, air conditioning use starts at approximately 11:00 a.m.
5. Continuous run times for central air conditioning differ due to varying ratio of air conditioner size and cooling requirements.

These observations have a significant impact on the usefulness of including air conditioning loads as a part of Minnkota's LM Program. However, discussion is first needed concerning the load shape of a typical summer peak day.

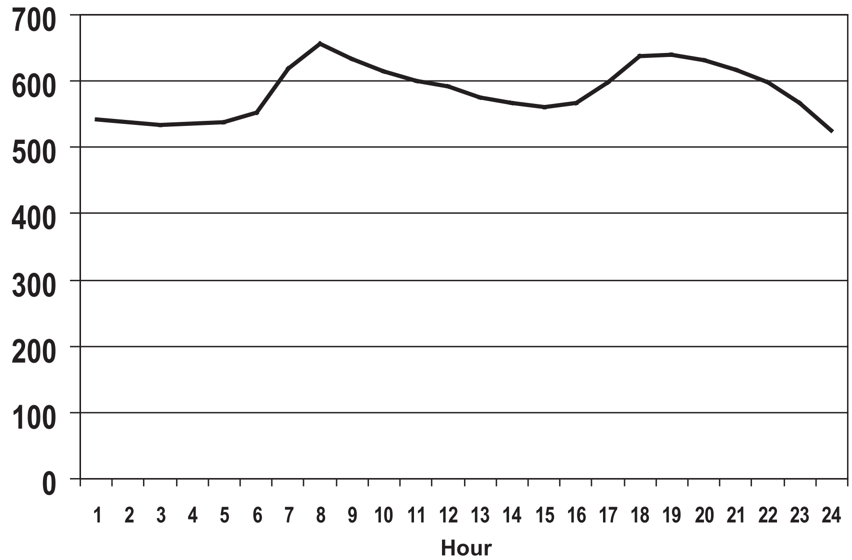
3.11 Load Shape of Summer Peak Day

The following chart displays the 24-hour load shape of a typical summer peak day. On a typical summer peak day the duration of the peak load period can be 12 hours, or longer. This has a significant impact on the types of loads that are suitable for use in Minnkota's LM Program.



For comparison purposes, the following chart displays a typical 24 hour winter peak day for the Joint System.

Load Shape of Typical Winter Peak Day



A typical winter peak day has morning and evening peaks that are four to five hours in duration with a considerable valley between peaks. The shorter duration peaks with a valley between peaks is of considerable importance in the LM strategy that Minnkota employs. For example, Load Group I loads, primarily water heaters, are to be interrupted for only four hours continuously and for only eight hours in any 24-hour time period. Load Group II loads, primarily thermal storage heat, are to be interrupted for up to 16 continuous hours in any 24-hour time period.

These types of operational restrictions have been carefully analyzed by Minnkota staff and have been integrated into the LM strategies that have evolved over the years. Even with the operational restraints placed on their use, Load Groups I and II loads are still a vital part of the LM Program.

3.12 Summer Season Operational Considerations

The shorter duration winter peaks with a valley between peaks, which allows time for such loads as water heaters and other storage heaters to be recharged, is a different situation then is faced with the summer peaks. The 12 hour, or longer, duration of the summer peaks effectively prohibits the use of short-term interruptible loads such as water heaters for summer season load management. Residential customers will exhaust their supply of hot water during the longer load management period required for the summer peaks.

After carefully analyzing the information gathered during the residential load survey and examining the hourly load profile of peak summer days, the following conclusions were reached concerning the cycling of air conditioning for summer load management.

1. Central air conditioning can operate for five continuous hours during 90 degree or warmer peak days. Therefore, cycling at or above these temperatures will raise the interior temperature of the facility. The amount of temperature rise will be dependent upon the cooling requirements, the size of the air conditioning unit and the amount of time the unit will be cycled.
2. Cooling requirements differ considerably across the Joint System's service territory with the result that cycling will impact those areas with higher requirements much more than the remaining areas.
3. Since "installed cooling capacity" versus "cooling load" ratios vary considerably from installation to installation and from area to area, a fixed cycling strategy would affect some end-users significantly more than others.

Despite the potential problems involved with cycling air conditioning, Minnkota and the member systems have included cycling of air conditioning loads as part of the LM Program.

Many of the above conclusions also apply to the cycling of water heaters. Therefore, the smaller residential water heaters are not utilized as a load to be cycled during the summer peaks load periods. However, there are a small number of water heaters that have larger storage capacity and are able to maintain sufficient hot water during the 12 hour interrupt period.

3.13 Summer Season Interruptible Load Estimates

Based on the last 11 years of operation experience with summer interruptible loads, the following is a forecast of the amount of demand relief that will be realized in future summer peak load periods.

Summer Season	Interruptible Load – MW
2006	48
2007	50
2008	50
2009	50
2010	51

2011	51
2012	52
2013	52
2014	53
2015	53
2016	53
2017	54
2018	54
2019	54
2020	55

3.14 Summer Season Schedule L Purchases

Minnkota has been purchasing Schedule L energy during the summer seasons and will continue to do so. Since, summer interruptible loads are considerably smaller than winter interruptible loads, the total amount of Schedule L energy purchased is much less than the total amount purchased in the winter season. Also, because many of the utilities in the upper Midwest are summer peaking, the amount of Schedule L energy available to purchase is significantly less during the summer season.

SECTION 4
Existing Resources

4.1 Overview

The Joint System has a variety of existing resources that economically and reliably fulfill the energy requirements of the end-use customers of its member systems and the NMPA municipals.

Existing generation resources consist of baseload plants, peaking units, biomass and wind units. Minnkota also purchases capacity and energy from its member systems and from the NMPA municipals.

Another important resource that the Joint System utilizes is its Load Management (LM) Program. The LM Program is a major tool that is instrumental in maintaining low energy costs and delaying the need for new generating plants.

Minnkota and eight of the NMPA municipals have firm power allocations from the Western Area Power Administration (WAPA). These firm power allocations have varying amounts of capacity and energy throughout the year.

4.2 Existing Generation

4.2.1 Milton R. Young Unit #1

Milton R. Young Unit #1 (Young #1) is Minnkota's primary source of baseload generation capacity. Young #1 was built and is operated and maintained by Minnkota. It is located approximately seven miles southeast of Center, N.D., and commenced commercial operation on November 20, 1970. Young #1 has MAPP accredited capability of 250 MW and is normally operated in the 225 MW range. The boiler is fired by lignite coal burned in a cyclone furnace.

Young #1 utilizes North Dakota lignite coal that averages 6,631 Btu per pound and contains approximately 0.83 percent sulfur. The coal is supplied from the Center mine by BNI Coal, Ltd. (BNI), under terms of a 50-year cost-plus contract. Minnkota's cost of lignite coal in 2004, including reclamation costs, was approximately $0.67 per million Btu. Lignite acreage from the Center mine is dedicated to Minnkota's usage by BNI and is essentially located on lands that are under private party control presently leased by BNI.

4.2.2 Milton R. Young Unit #2

Milton R. Young Unit #2 (Young #2) is the second unit constructed at the Milton R. Young Station. This unit consists of a 455 MW lignite-fired cyclone boiler plant and a 463 mile +/- 250 kV direct current transmission line from Center, N.D., to Duluth, Minn. Young #2 commenced commercial operation in May 1977 and is owned by Square Butte Electric Cooperative (Square Butte). Square Butte is an electric cooperative association affiliated with Minnkota by virtue of the fact that the 11 member-owners of Minnkota also own Square Butte.

Young #2 is operated and maintained by Minnkota pursuant to an operating agreement with Square Butte. Under the terms of a power sales agreement, subject to the options described below, Square Butte sells 65.625 percent of the capacity (approximately 298.600 MW) of Young #2 to Minnesota Power. Square Butte, through another power sales agreement, sells the remaining 34.375 percent (approximately 156.400 MW) of Young #2 capacity to Minnkota.

Beginning January 1, 2007, Square Butte has the option to retain another 23.700 MW of Young #2 capacity. Square Butte has similar options for 2008 and 2009. With the execution of these options, Square Butte will retain 50 percent of the total Young #2 capacity. The remaining 50 percent capacity will continue to be purchased by Minnesota Power. All of the retained capacity will be utilized to serve Joint System energy requirements. For this IRP, it was assumed that Square Butte would exercise all of its options.

4.2.3 Coyote Plant

The Coyote Plant is a 427 MW (MAPP Net URGE Rating) lignite-fired mine-mouth generating station located southwest of Beulah, N.D., and operated by Otter Tail Power Company. The Northern Municipal Power Agency (NMPA) owns a 30 percent share (128.100 MW) of this unit and has appointed Minnkota as its agent for scheduling capacity and energy from Coyote and for operational management responsibilities.

4.2.4 Ainsworth Cogeneration Plant

The Ainsworth (formerly Potlatch) cogeneration plant is an 11.174 MW facility located near Bemidji, Minn. This facility utilized approximately 150,000 tons of waste wood per year from an oriented strand board (OSB) manufacturing facility and a lumber mill to produce stream for processing and generating electricity. The retail load is jointly served by Otter Tail Power Company and Beltrami Electric Cooperative, one of the member-owners of Minnkota. The electrical output of the cogeneration facility is purchased by Otter Tail Power Company and Minnkota. Both Otter Tail and Minnkota receive approximately 5.587 MW of capacity and 30,000,000 kWh of energy annually from the facility.

4.2.5 Minnkota Diesel Generation

Minnkota owns 14 diesel units with a total generating capacity of 14.841 MW. Eleven of the diesel units are located in Grand Forks, N.D., and three units are located in Harwood, N.D. The Grand Forks plant has a total capacity of 10.282 MW and the Harwood plant has a total capacity of 4.559 MW.

Since diesel generation has high fuel costs and high maintenance costs, the Grand Forks and Harwood plants are normally utilized for MAPP generation reserve requirements and emergency situations.

4.2.6 Infinity Wind Generation

Minnkota's Infinity Wind Program consists of two 0.900 MW wind turbines, one located near Valley City, N.D., and one located near Petersburg, N.D. The Valley City turbine commenced operation on January 25, 2002. The Petersburg turbine became operational on July 12, 2002. Both units are expected to produce approximately 2,800 MWh annually.

4.2.7 Thief River Falls Hydro Plant

Thief River Falls, a NMPA member municipal, owns and operates a 0.500 MW hydro plant that has been in operation since 1927. This unit produces an average of 2,000 MWh annually, which serves Thief River Falls municipal load.

4.2.8 Cass County Electric Cooperative Diesel Generation

Minnkota leases 10 diesel generating units on behalf of Cass County Electric Cooperative. These generators are located at several substations and are the financial responsibility of Cass County. Minnkota purchases the capacity and energy from these units when needed. The 10 diesel generators have a total capacity rating of 18.280 MW. Minnkota also accredits, for MAPP reporting requirements, two of Cass County's customer-owned diesel generators that have capacity ratings of 2.000 MW and 0.940 MW.

4.2.9 NMPA Diesel Generation

Four of the NMPA municipal members – Thief River Falls, Grafton, Halstad and Hawley – have diesel generators that are leased to Minnkota. The total capacity of the NMPA diesel generation is 12.193 MW.

4.2.10 Miscellaneous Generation

Minnkota accredits, for MAPP reporting requirements, the generating capacity of the American Crystal Sugar plants at Drayton, N.D., and at Hillsboro, N.D. The Drayton generation has a rated capacity of 6.920 MW and the Hillsboro generation has a rated capacity of 13.386 MW.

4.3 Existing Power Contracts

4.3.1 Western Area Power Administration Firm Power Allocation to Minnkota.

Minnkota has a Firm Power Allocation from the Western Area Power Administration (WAPA). This allocation provides for firm capacity and energy to the Joint System of 73.300 MW and 362,221 MWh per year.

4.3.2 Western Area Power Administration Firm Power Allocation to the NMPA Municipals.

Eight of the 12 NMPA municipals have a WAPA Firm Power Allocation. These allocations provide for firm capacity and energy to the Joint System of 37.711 MW and 163,559 MWh per year.

4.3.3 Otter Tail Power Company Sale of 2 MW

Minnkota is in the Otter Tail Power Company (OTP) balancing authority area. Utilities, such as OTP, that have balancing authority area responsibilities incur expenses in fulfilling those obligations. In addition, OTP also provides load swing regulation for Minnkota. As partial compensation to OTP for these services, Minnkota sells 2 MW of capacity and energy at a reduced rate to OTP.

4.3.4 Xcel Energy Sale of 100 MW

Minnkota sells Xcel Energy 100 MW of capacity and energy for the summer season (May through October) through 2015. Energy sales associated with this capacity are delivered to Xcel Energy based on the availability of the Coyote Plant.

4.3.5 Basin Electric Power Cooperative 20 MW Purchase

Minnkota has purchased 20 MW of System Participation Power from Basin Electric Power Cooperative for the July through September 2006 time period.

4.4 Joint System Load Management Program

The Joint System Load Management (LM) Program is a major tool that is instrumental in maintaining low energy costs and delaying the need for new generating plants. The LM Program is documented in Section 3 of this IRP.

4.5 Transmission Facilities

Minnkota's transmission facilities consist of 214 miles of 345 kV, 363 miles of 230 kV, 226 miles of 115 kV and 2,139 miles of 69 kV lines. NMPA owns a 15 percent undivided interest in Minnkota's transmission system.

The transmission system is directly interconnected with seven area utilities: Manitoba Hydro, Montana-Dakota Utilities Company, Minnesota Power, Otter Tail Power Company, Xcel Energy, Great River Energy and the Western Area Power Administration (WAPA).

Minnkota's extensive transmission system and large number of interconnections with other utilities serves to enhance service reliability to the end-use customer and permits the sale or purchase of energy from neighboring companies.

SECTION 5

Load Forecast

5.1 Overview

The primary function of the Integrated Resource Plan (IRP) is to demonstrate how a utility plans on supplying the energy requirements of its end-use consumers over the next 15 years. The IRP documents the resource and demand side options that best fit the utility's forecasted energy requirements.

This is the fourth IRP that Minnkota Power Cooperative, Inc. and the Northern Municipal Power Agency (NMPA) have filed jointly with the Minnesota Public Utilities Commission under MN Statute 216b.2422 and MN Rules Part 7843. The format of this IRP is somewhat different from the earlier filings, but utilizes the same general methodology of the previous plans.

5.2 Resource Plan Objectives

The objectives of this IRP are based on the resource planning requirements of Minnkota and the NMPA and fulfill the evaluation criteria requirements of MN Rules Part 7843.

Study Objective #1: Maintain or improve the adequacy and reliability of utility service.

Study Objective #2: Keep customers' bills and the utility's rates as low as practicable, given regulatory and other constraints.

Study Objective #3: Minimize adverse socioeconomic effects and adverse effects upon the environment.

Study Objective #4: Enhance the utility's ability to respond to changes in the financial, social and technological factors affecting its operations.

Study Objective #5: Limit the risk of adverse effects on the utility and its customers from financial, social and technological factors that the utility cannot control.

5.3 Load Forecast

As noted earlier in this IRP, Minnkota Power Cooperative (Minnkota) and the Northern Municipal Power Agency (NMPA) have formed a "Joint System" to fulfill the power supply and the transmission requirements for delivery of wholesale power to the 11 member-owner distribution cooperatives that own Minnkota and the 12 municipal members of the NMPA.

The Joint System load forecast is comprised of the Minnkota Power Requirements Study and a load forecast of the 12 NMPA municipal systems.

The member-owner distribution cooperatives and Minnkota are required to complete a Rural Utilities Service (RUS)-approved Power Requirements Study (PRS). The PRS is on a two-year cycle, meaning that new studies of the individual member-owners and Minnkota are completed every other year. The latest PRSs were completed in 2005.

The municipal members of the NMPA are not required to complete a PRS. However, a load forecast utilizing a linear regression analysis of the historical period 1988 through 2004 was completed for each of the members of the NMPA.

This section documents Minnkota's 2005 PRS and the NMPA forecast and their adaptation into the 2006 IRP. The Minnkota load forecast and the NMPA load forecast were combined to provide an estimate of future Joint System energy and capacity requirements. This combined forecast is also utilized in system transmission planning, load management operations and planning, demand side management studies, power cost studies, regulatory reporting, RUS loan applications and marketing evaluations.

5.4 Power Requirements Study

Rural Utilities Service (RUS) defines a Power Requirements Study (PRS) as a "thorough study of a borrower's electric loads and the factors that affect those loads in order to determine, as accurately as practicable, the borrower's future requirements for energy and capacity. The PRS of a power supply borrower includes and integrates the PRSs of its member systems." The PRS must meet the guidelines and procedures outlined in Title 7 Part 1710 Subpart E of the Code of Federal Regulations, which defines the purposes, basic policies, requirements and criteria that must be met before RUS will approve a PRS. All applicable RUS regulations and standards have been observed and RUS representatives have been involved in the 1992 PRS, 1995 PRS, 1997 PRS, 1999 PRS, 2001 PRS, 2003 PRS and the 2005 PRS.

5.5 PRS Work Plan

The 2005 PRS Work Plan was drafted by Clearspring Energy Advisors for Minnkota, the member systems and RUS. The Work Plan, which is required by RUS, outlined each step of the 2005 PRS, including the analysis employed, work schedule and the participants' responsibilities. The objective of the Work Plan is to provide all parties to the study with the knowledge of what was to be done, what was expected from each participant and what the PRS will encompass. Comments and input were solicited from member systems and from Minnkota staff. Any input collected during the review process is to be incorporated into the revised Work Plan to ensure a mutually agreeable project approach and schedule for all parties. The revised Work Plan was sent to each of the member systems, Minnkota and RUS headquarters in Washington, D.C. All parties have to agree to the revised Work Plan and any deviations from the Work Plan have to be acceptable to all study participants.

5.6 PRS Approach

Economic modeling was the primary forecasting technique utilized in the member systems' PRS. Econometric modeling identifies relationships between energy use and economic, demographic and system trends. The models are based upon 10 years of historical data and utilize such factors as population, employment, income, weather, electricity prices, alternate fuel prices, agricultural economic conditions, as well as other factors pertinent to model development. The studies specifically determined and quantified the factors that historically had impacts on electrical usage.

Econometric models were developed to forecast the number of residential consumers, residential energy usage, the number of small commercial consumers and small commercial usage.

Forecasts for the number of large commercial customers and usage were developed judgmentally, based on input from the member systems or the large commercial customers.

Judgment and trend analysis were utilized to forecast irrigation sales, street lighting, sales to public authorities, sales for resale, own usage and losses for each of the member systems.

Models were developed using the ordinary least squares approach to regression analysis. All of the models and their resulting forecasts were selected on the basis of theoretical and statistical validity and reasonableness of results.

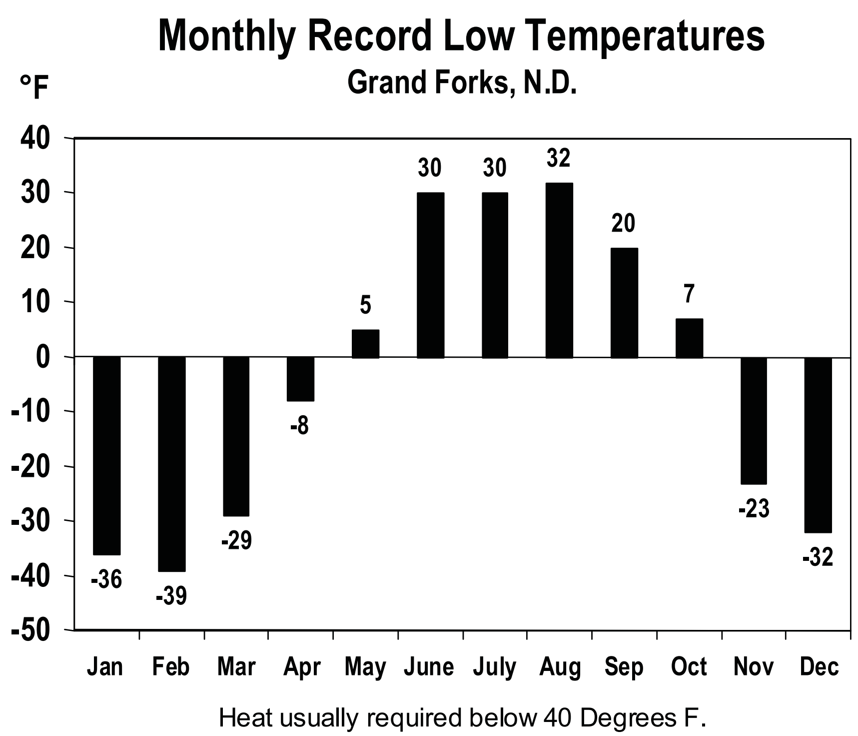
Minnkota's PRS was developed in a bottom-up manner. The individual member system's energy and capacity requirements forecasts were summated to form Minnkota's base forecast. A forecast of Minnkota's transmission losses and its own energy usage, a forecast of the Cavalier Air Force Station energy requirements (based on historical usage) and the forecast of the NMPA energy requirements were then added to the base forecast to obtain the total Joint System energy requirements forecast. The forecast of seasonal (winter and summer) peak demand is based on load factor calculations.

5.7 Weather Sensitivity

The Joint System experiences significant differences in the peak demand for the summer and winter seasons. These differences are mainly due to the extreme cold winter weather versus the relatively mild summer weather and the saturation of heating load versus cooling load throughout the service territory.

Throughout Minnkota's service territory, the average number of days per year with the minimum temperature below zero is 53. The average number of days per year with the temperature above 90 degrees is 8. The harsh winters, combined with a 30 percent heating saturation of off-peak heating systems, have resulted in winter peak demand significantly higher than summer peak demands.

The following chart displays the record low temperatures that have occurred in Grand Forks, N.D., which is located near the center of the service territory:



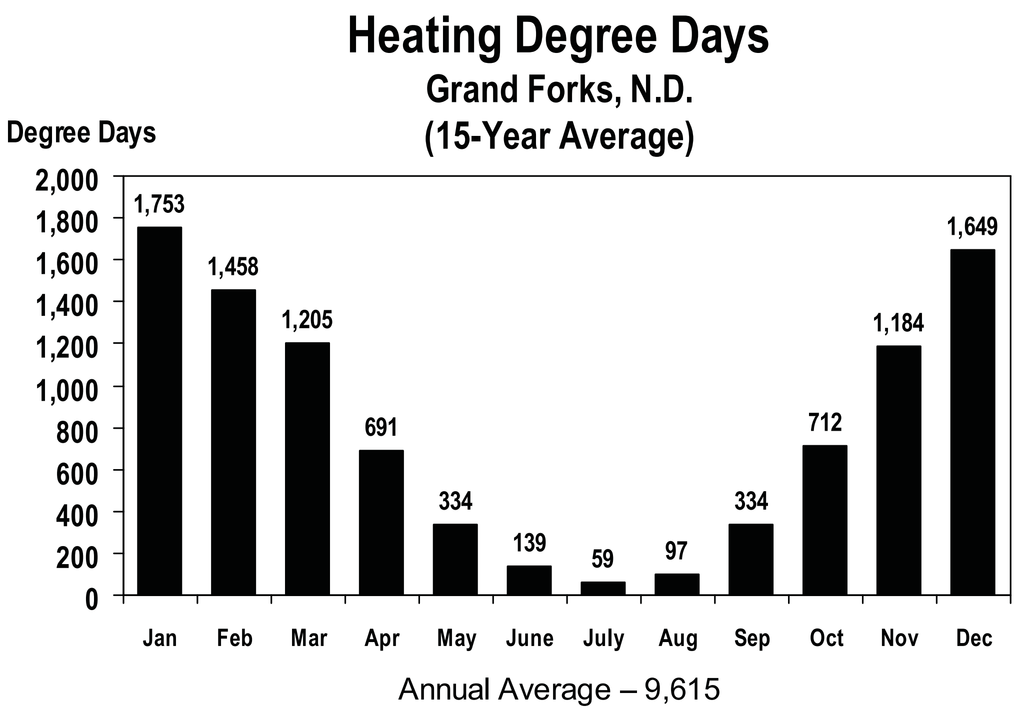
5.8 Heating and Cooling Degree Days

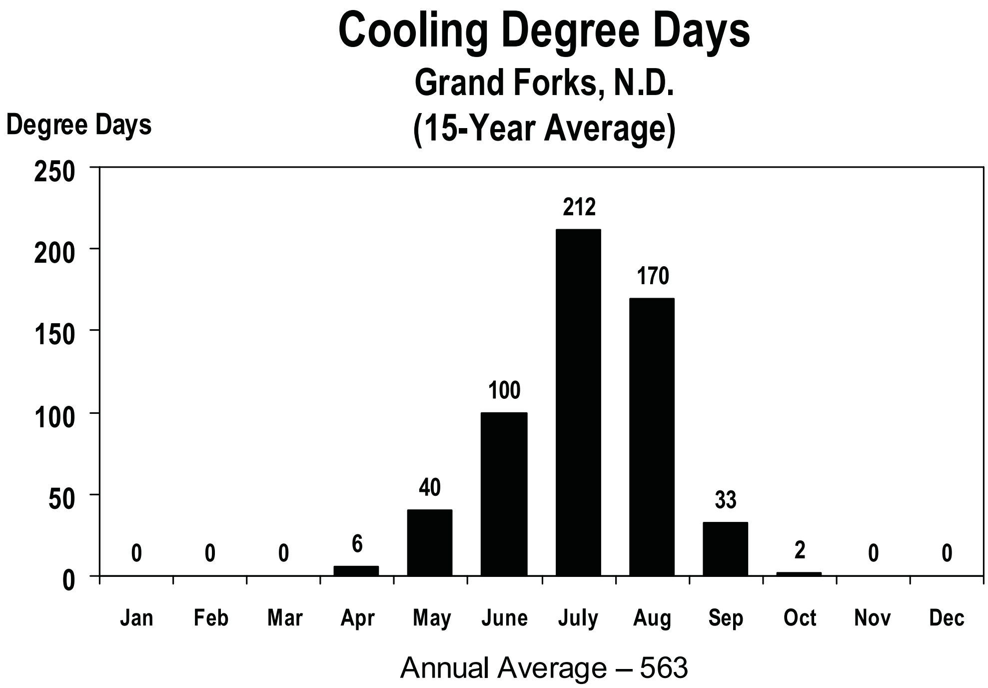
One method of determining the relative amounts of heating and cooling requirements due to daily temperature variation is the degree day calculation. These calculations help quantify the differences in monthly, seasonal and annual temperatures and are utilized in analyzing the impact that weather has on electric load.

Heating degree days are calculated as the difference between 65 degrees F and the average of all hourly temperatures that fall below 65 degrees F.

Cooling degree days are calculated as the difference between 65 degrees F and all hourly temperatures above 65 degrees F.

Minnkota has been tracking this data for the last 15 years. The 15-year average of heating degree days is 9,615 and the 15-year average for cooling degree days is 563. The monthly heating and cooling degree day values for the Grand Forks area is graphically displayed below.





5.9 Joint System Customer Growth

The number of customers the Joint System will be serving is projected to increase at a rate of 2.5 percent per year for the 2006-2020 time frame.

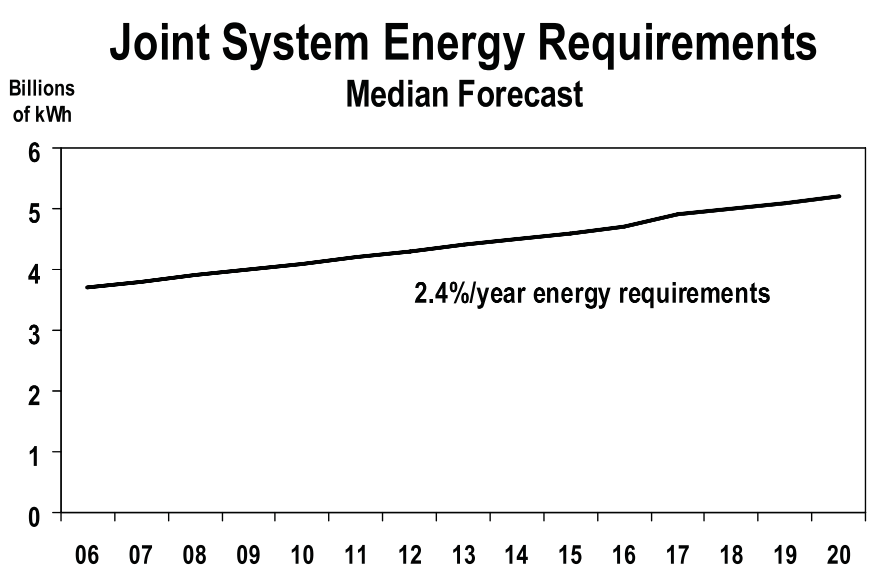
5.10 Median Energy Forecast

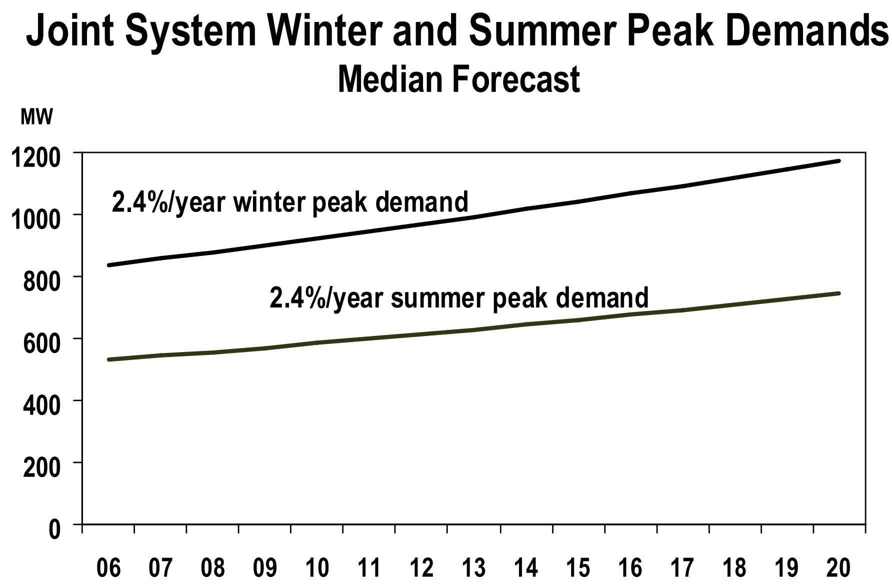
As noted earlier in this section, Minnkota's PRS is the result of the summation of the forecasts of the individual member cooperative's future energy requirements. To this initial energy requirement forecast, an estimate of Minnkota's future transmission losses and own usage were added. Next an estimate of the Cavalier Air Force Station energy requirements (based on historical usage) was added to the total. The last step was to combine Minnkota's total energy requirements and the NMPA energy requirements to develop a comprehensive long-term forecast of the total energy requirements of the Joint System. The forecast of winter and summer peak demands is derived utilizing load factor estimates. Load factor estimates are based on historical data.

The Joint System median forecast of its annual energy requirements, winter peak demands and summer peak demands are shown in the following table:

Year	Annual Energy Requirements MWh	Winter Peak Forecast MW	Summer Peak Forecast MW
2006	3,954,538	836	530
2007	4,073,128	861	546
2008	4,146,197	877	556
2009	4,248,756	898	569
2010	4,359,523	922	585
2011	4,466,766	944	598
2012	4,580,059	968	614
2013	4,694,605	992	629
2014	4,812,122	1,017	645
2015	4,927,613	1,042	661
2016	5,045,876	1,067	676
2017	5,166,977	1,092	692
2018	5,290,984	1,119	709
2019	5,417,968	1,145	726
2020	5,548,000	1,173	744

The above information is graphically displayed in the following charts.





The Joint System's median forecast of total energy requirements project a 2.4 percent per year increase for the next 15 years. The winter peak demand is projected to increase at a rate of 2.4 percent per year and the summer peak demand is projected to increase at a rate of 2.4 percent per year.

5.11 Bandwidth Energy Forecast

Analysis was done to determine the sensitivity of projected load growth to weather, the economy and alternate fuel prices. This work was included in the PRS and has been incorporated into this IRP.

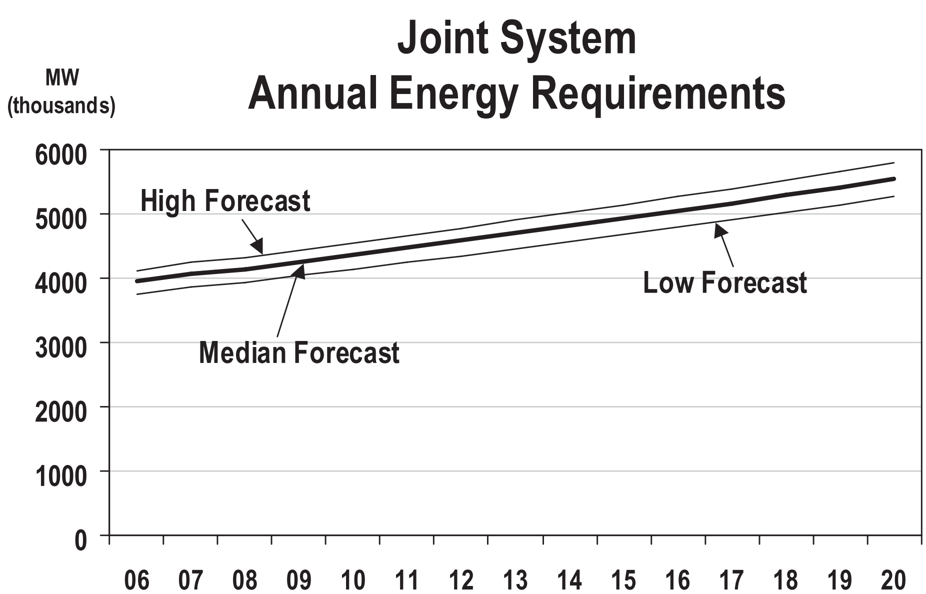
The low load growth scenario was based on the impacts that extremely mild weather would have on the forecast. The high load growth scenario was based on the impacts that extremely harsh weather would have on the forecast. Weather was found to impact the forecast more than any other factor.

These two scenarios are the basis for the bandwidth forecasts for the member systems. Although the sensitivity analyses were only studied for the member systems, the same percentage variation was applied to the Joint System energy requirements, since the characteristics of the municipals' electric load is similar to those of the member systems' load characteristics.

The following table lists the Joint System's annual energy requirements for the high, median and low growth scenarios:

Year	Low Growth Forecast Energy Requirements MWh	Median Growth Forecast Energy Requirements MWh	High Growth Forecast Energy Requirements MWh
2006	3,760,334	3,954,538	4,125,940
2007	3,872,026	4,073,128	4,250,318
2008	3,940,853	4,146,197	4,326,942
2009	4,037,061	4,248,756	4,434,969
2010	4,141,339	4,359,523	4,551,169
2011	4,242,158	4,466,766	4,663,791
2012	4,348,529	4,580,059	4,782,958
2013	4,456,168	4,694,605	4,903,290
2014	4,566,446	4,812,122	5,026,937
2015	4,676,041	4,927,613	5,147,583
2016	4,788,266	5,045,876	5,271,125
2017	4,903,184	5,166,977	5,397,632
2018	5,020,860	5,290,984	5,527,175
2019	5,141,361	5,417,968	5,659,827
2020	5,264,754	5,548,000	5,795,663

The following chart graphically depicts the Joint System's annual energy requirements for the low, median and high load growth forecasts from the previous table:

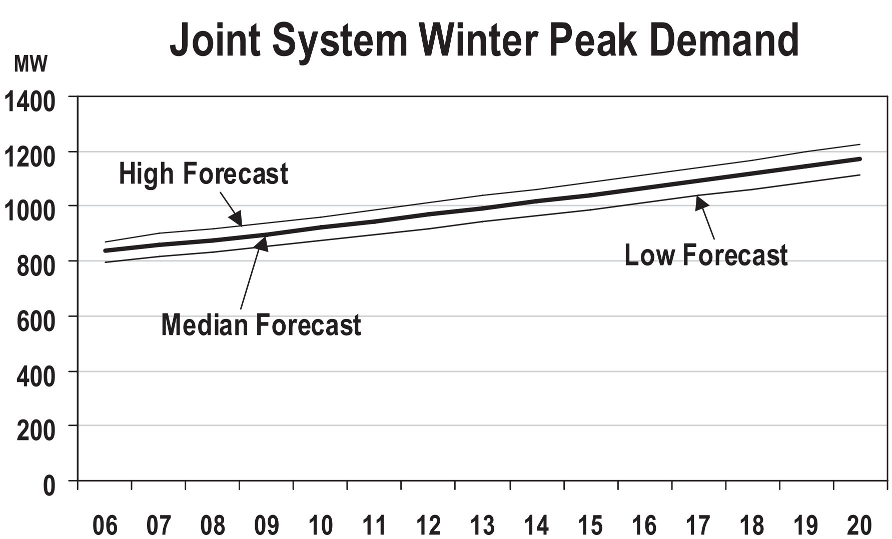


5.12 Winter Peak Bandwidth Forecasts

The following table lists the winter peak demands that were derived from the low, median and high forecasts of the Joint System's future energy requirements:

Year	Winter Peak Low Growth Forecast MW	Winter Peak Median Growth Forecast MW	Winter Peak High Growth Forecast MW
2006	795	836	872
2007	819	861	899
2008	833	877	915
2009	853	898	938
2010	875	922	962
2011	897	944	986
2012	919	968	1,011
2013	942	992	1,037
2014	965	1,017	1,063
2015	989	1,042	1,088
2016	1,012	1,067	1,114
2017	1,037	1,092	1,141
2018	1,061	1,119	1,168
2019	1,087	1,145	1,196
2020	1,113	1,173	1,225

The following chart is a graphic display of the winter peak demands from the previous table:

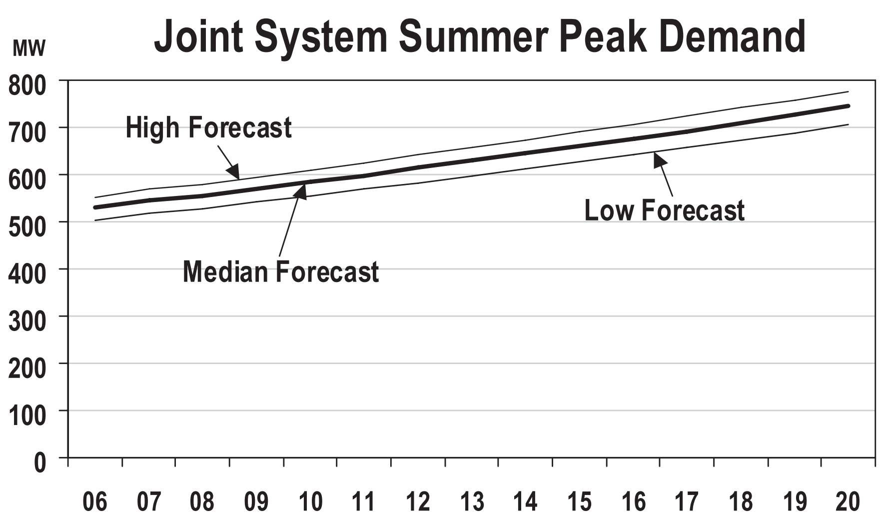


5.13 Summer Peak Bandwidth Forecasts

The following table lists the summer peak demands that were derived from the low, median and high forecast of the Joint System's future energy requirements:

Year	Summer Peak Low Growth Forecast MW	Summer Peak Median Growth Forecast MW	Summer Peak High Growth Forecast MW
2006	504	530	553
2007	519	546	570
2008	528	556	580
2009	541	569	595
2010	555	585	610
2011	569	598	625
2012	583	614	641
2013	597	629	657
2014	612	645	674
2015	627	661	690
2016	642	676	706
2017	657	692	723
2018	673	709	741
2019	689	726	758
2020	706	744	777

The following chart is a graphical display of the summer peak demand from the previous table:



SECTION 6

Load and Capability Report

6.1 Introduction

As part of the responsibilities of belonging to MAPP, Minnkota is required to maintain, either by owning generation or by capacity purchases, sufficient generation capacity to serve 115 percent of its annual peak demand. The additional 15 percent is required by MAPP for reserves, which may be needed to serve unexpected load growth or system emergencies. Each member of MAPP has a similar obligation to carry reserves.

Since all MAPP members carry reserves, and since one of the benefits of belonging to MAPP is the ability to coordinate capacity additions with other members, utilities such as Minnkota are not required to carry larger reserves to maintain the degree of reliability that its customers have come to expect.

However, if a MAPP utility's actual load plus reserve obligation exceeds its net generation capability, then it is required to purchase generation capacity from other MAPP members. The purchase is usually at a much higher rate than if the utility had made its own arrangements prior to becoming deficit. The reason for the stiff penalty is to ensure that adequate and timely generation capacity additions materialize to maintain a high degree of reliability for the end-use customers.

MAPP has developed a Load and Capability (L&C) Report to help its members plan their future capacity requirements. The L&C Report is a forecast of the utility's generation, load and reserve requirements. This Report takes into account not only the utility's load and generation, but also sales and purchases. Schedule L purchases are also taken into account in this Report. It is an important planning tool for MAPP utilities, since it aids forecasting the amount of future generation capacity that will be required by taking into account the needed planning reserves.

The Joint System does not complete a L&C Report; only Minnkota does. However, Minnkota does have the responsibility of providing for the future load growth of the NMPA municipals, and therefore must take into account the reserve capacity obligation as well as the load growth of the NMPA. This is done by completing a L&C Report for the Joint System. The Joint System L&C Report is used for internal planning purposes.

Because of the large variations that can occur in peak demand due to weather and the economy, among other things, peak demand forecasting is difficult. With the difficulty in peak demand forecasting and the stiff MAPP penalties for those utilities that are deficit in generation capacity, generation planning at Minnkota tends to be conservative. Conservative generation planning, in this case, means having sufficient generation capacity available to cover unlikely, but possible, peak demand situations. This is especially true for the near term, since it may be extremely difficult to arrange for additional capacity on short notice.

The Joint System Load & Capability Reports for the low, median and high growth forecasts for the winter and summer seasons are included in the following pages of this section. These L&C Reports take into account the Joint System load and generation forecasts as well as the existing and future sales and purchases from other utilities.

The information provided from the L&C Reports helps determine the direction that Minnkota will take in its Two-Year and Five-Year Action Plans, and in long-term generation expansion planning.

Joint System Load and Capability Report for 2006-2020
MAPP Winter Season (November 1 Through April 30)
Low Growth Forecast

	05-06	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20
Joint System Maximum Demand	795	819	833	853	875	897	919	942	965	989	1,012	1,037	1,061	1,087	1,113
NMPA WAPA Allocation	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Seasonal Maximum Demand	761	785	799	819	841	863	885	908	931	955	978	1,003	1,027	1,053	1,079
Schedule L Purchases	250	257	260	265	270	275	281	286	291	297	302	307	313	318	324
Seasonal System Demand	511	528	539	554	571	588	604	622	640	658	676	696	714	735	755
Annual System Demand	511	528	539	554	571	588	604	622	640	658	676	696	714	735	755
Firm Purchases	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seasonal Adjusted Net Demand	438	455	466	481	498	515	531	549	567	585	603	623	641	662	682
Annual Adjusted Net Demand	438	455	466	481	498	515	531	549	567	585	603	623	641	662	682
Net Generating Capability	597	621	645	668	668	668	668	668	668	668	668	668	668	668	668
Participation Purchases	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Participation Sales	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Adjusted Net Capability	607	631	655	678	678	678	678	678	678	678	678	678	678	678	678
Net Reserve Capacity Obligation	66	68	70	72	75	77	80	82	85	88	90	93	96	99	102
Total Firm Capacity Obligation	503	523	536	553	572	592	610	631	652	672	693	716	737	761	784
Surplus or Deficit (-) Capacity	104	108	119	126	106	86	68	47	27	6	-15	-38	-58	-83	-106

Joint System Load and Capability Report for 2006-2020
MAPP Winter Season (November 1 Through April 30)
Median Growth Forecast

	05-06	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20
Joint System Maximum Demand	836	861	877	898	922	944	968	992	1,017	1,042	1,067	1,092	1,119	1,145	1,173
NMPA WAPA Allocation	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Seasonal Maximum Demand	802	827	843	864	888	910	934	958	983	1,008	1,033	1,058	1,085	1,111	1,139
Schedule L Purchases	250	257	260	265	270	275	281	286	291	297	302	307	313	318	324
Seasonal System Demand	552	570	583	599	618	635	653	672	692	711	731	751	772	793	815
Annual System Demand	552	570	583	599	618	635	653	672	692	711	731	751	772	793	815
Firm Purchases	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seasonal Adjusted Net Demand	479	497	510	526	545	562	580	599	619	638	658	678	699	720	742
Annual Adjusted Net Demand	479	497	510	526	545	562	580	599	619	638	658	678	699	720	742
Net Generating Capability	597	621	645	668	668	668	668	668	668	668	668	668	668	668	668
Participation Purchases	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Participation Sales	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Adjusted Net Capability	607	631	655	678	678	678	678	678	678	678	678	678	678	678	678
Net Reserve Capacity Obligation	72	75	76	79	82	84	87	90	93	96	99	102	105	108	111
Total Firm Capacity Obligation	551	571	586	605	626	646	667	689	712	733	756	779	804	828	853
Surplus or Deficit (-) Capacity	57	60	68	74	52	32	12	-10	-33	-55	-78	-101	-125	-149	-175

Joint System Load and Capability Report for 2006-2020
MAPP Winter Season (November 1 Through April 30)
High Growth Forecast

	05-06	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20
Joint System Maximum Demand	872	899	915	938	962	986	1,011	1,037	1,063	1,088	1,114	1,141	1,168	1,196	1,225
NMPA WAPA Allocation	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Seasonal Maximum Demand	838	865	881	904	928	952	977	1,003	1,029	1,054	1,080	1,107	1,134	1,162	1,191
Schedule L Purchases	250	257	260	265	270	275	281	286	291	297	302	307	313	318	324
Seasonal System Demand	588	608	621	639	658	677	696	717	738	757	778	800	821	844	867
Annual System Demand	588	608	621	639	658	677	696	717	738	757	778	800	821	844	867
Firm Purchases	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seasonal Adjusted Net Demand	515	535	548	566	585	604	623	644	665	684	705	727	748	771	794
Annual Adjusted Net Demand	515	535	548	566	585	604	623	644	665	684	705	727	748	771	794
Net Generating Capability	597	621	645	668	668	668	668	668	668	668	668	668	668	668	668
Participation Purchases	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Participation Sales	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Adjusted Net Capability	607	631	655	678	678	678	678	678	678	678	678	678	678	678	678
Net Reserve Capacity Obligation	77	80	82	85	88	91	93	97	100	103	106	109	112	116	119
Total Firm Capacity Obligation	592	615	630	651	672	694	716	740	764	786	810	836	860	886	913
Surplus or Deficit (-) Capacity	15	16	25	28	6	-16	-38	-62	-86	-108	-132	-157	-182	-208	-234

Joint System Load and Capability Report for 2006-2020
MAPP Summer Season (May 1 Through October 30)
Low Growth Forecast

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Joint System Maximum Demand	504	519	528	541	555	569	583	597	612	627	642	657	673	689	706
NMPA WAPA Allocation	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Seasonal Maximum Demand	473	488	497	510	524	538	552	566	581	596	611	626	642	658	675
Schedule L Purchases	48	50	50	50	51	51	52	52	53	53	53	54	54	54	55
Seasonal System Demand	425	438	447	460	473	487	500	514	528	543	558	572	588	604	620
Annual System Demand	552	570	583	599	618	635	653	672	692	711	731	751	772	793	815
Firm Purchases	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seasonal Adjusted Net Demand	376	389	398	411	424	438	451	465	479	494	509	523	539	555	571
Annual Adjusted Net Demand	503	521	534	550	569	586	604	623	643	662	682	702	723	744	766
Net Generating Capability	585	608	632	655	655	655	655	655	655	655	655	655	655	655	655
Participation Purchases	32	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Participation Sales	102	102	102	102	102	102	102	102	102	102	2	2	2	2	2
Adjusted Net Capability	515	518	542	565	565	565	565	565	565	565	665	665	665	665	665
Net Reserve Capacity Obligation	75	78	80	82	85	88	91	93	96	99	102	105	108	112	115
Total Firm Capacity Obligation	451	467	478	493	509	525	541	558	575	593	611	628	647	666	685
Surplus or Deficit (-) Capacity	64	52	64	72	56	40	24	7	-10	-28	54	37	18	-1	-20

Joint System Load and Capability Report for 2006-2020
MAPP Summer Season (May 1 Through October 30)
Median Growth Forecast

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Joint System Maximum Demand	530	546	556	569	585	598	614	629	645	661	676	692	709	726	744
NMPA WAPA Allocation	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Seasonal Maximum Demand	499	515	525	538	554	567	583	598	614	630	645	661	678	695	713
Schedule L Purchases	48	50	50	50	51	51	52	52	53	53	53	54	54	54	55
Seasonal System Demand	451	465	475	488	503	516	531	546	561	577	592	607	624	641	658
Annual System Demand	552	570	583	599	618	635	653	672	692	711	731	751	772	793	815
Firm Purchases	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seasonal Adjusted Net Demand	402	416	426	439	454	467	482	497	512	528	543	558	575	592	609
Annual Adjusted Net Demand	503	521	534	550	569	586	604	623	643	662	682	702	723	744	766
Net Generating Capability	585	608	632	655	655	655	655	655	655	655	655	655	655	655	655
Participation Purchases	32	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Participation Sales	102	102	102	102	102	102	102	102	102	102	2	2	2	2	2
Adjusted Net Capability	515	518	542	565	565	565	565	565	565	565	665	665	665	665	665
Net Reserve Capacity Obligation	75	78	80	82	85	88	91	93	96	99	102	105	108	112	115
Total Firm Capacity Obligation	477	494	506	521	539	554	572	590	608	627	645	663	683	703	723
Surplus or Deficit (-) Capacity	38	25	36	44	26	11	-7	-25	-43	-62	20	2	-18	-38	-58

Joint System Load and Capability Report for 2006-2020
MAPP Summer Season (May 1 Through October 30)
High Growth Forecast

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Joint System Maximum Demand	553	570	580	595	610	625	641	657	674	690	706	723	741	758	777
NMPA WAPA Allocation	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
Seasonal Maximum Demand	522	539	549	564	579	594	610	626	643	659	675	692	710	727	746
Schedule L Purchases	48	50	50	50	51	51	52	52	53	53	53	54	54	54	55
Seasonal System Demand	474	489	499	514	528	543	558	574	590	606	622	638	656	673	691
Annual System Demand	552	570	583	599	618	635	653	672	692	711	731	751	772	793	815
Firm Purchases	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seasonal Adjusted Net Demand	425	440	450	465	479	494	509	525	541	557	573	589	607	624	642
Annual Adjusted Net Demand	503	521	534	550	569	586	604	623	643	662	682	702	723	744	766
Net Generating Capability	585	608	632	655	655	655	655	655	655	655	655	655	655	655	655
Participation Purchases	32	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Participation Sales	102	102	102	102	102	102	102	102	102	102	2	2	2	2	2
Adjusted Net Capability	515	518	542	565	565	565	565	565	565	565	665	665	665	665	665
Net Reserve Capacity Obligation	75	78	80	82	85	88	91	93	96	99	102	105	108	112	115
Total Firm Capacity Obligation	500	518	530	547	564	581	599	618	637	656	675	694	715	735	756
Surplus or Deficit (-) Capacity	15	1	12	18	1	-16	-34	-53	-72	-91	-10	-29	-50	-70	-91

SECTION 7

Resource Plan Development

7.1 Introduction

The primary function of the Integrated Resource Plan (IRP) is to demonstrate how a utility plans on supplying the energy requirements of its end-use consumers over the next 15 years. The IRP documents the resource and demand side options that best fit the utility's forecasted energy requirements.

This section documents how the load forecasts, existing generation, power sales and purchases, and the impacts of load management are integrated to form a cohesive view of the future power supply situation for Minnkota's member systems and the NMPA municipals.

7.2 Load Forecast

As noted in Section 5, Minnkota Power Cooperative (Minnkota) and the Northern Municipal Power Agency (NMPA) have formed a "Joint System" to fulfill the power supply and the transmission requirements for delivery of wholesale power to the 11 member-owner distribution cooperatives that own Minnkota and the 12 municipal members of the NMPA.

The Joint System load forecast is comprised of the Minnkota Power Requirements Study and a load forecast of the 12 NMPA municipal systems.

The member-owner distribution cooperatives and Minnkota are required to complete a Rural Utilities Service (RUS)-approved Power Requirements Study (PRS). The PRS is on a two-year cycle, meaning that new studies of the individual member-owners and Minnkota are completed every other year. The latest PRSs were completed in 2005.

The municipal members of the NMPA are not required to complete a PRS. However, a load forecast utilizing a linear regression analysis of the historical period 1988 through 2004 was completed for each of the members of the NMPA.

The Minnkota load forecast and the NMPA load forecast were combined to provide an estimate of future Joint System energy and capacity requirements.

7.3 Power Requirements Study

Rural Utilities Service (RUS) defines a Power Requirements Study (PRS) as a "thorough study of a borrower's electric loads and the factors that affect those loads in order to determine, as accurately as practicable, the borrower's future requirements for energy and capacity. The PRS of a power supply borrower includes and integrates the PRSs of its member systems."

7.4 PRS Work Plan

The 2005 PRS Work Plan was drafted by Clearspring Energy Advisors for Minnkota, the member systems and RUS. The Work Plan, which is required by RUS, outlined each step of the 2005 PRS, including the analysis employed, work schedule and the participants' responsibilities. The objective of the Work Plan is to provide all parties to the study with the knowledge of what was to be done, what was expected from each participant and what the PRS will encompass. Comments and input were solicited from member systems and from Minnkota staff. Any input collected during the review process is to be incorporated into the revised Work Plan to ensure a mutually agreeable project approach and schedule for all parties. The revised Work Plan was sent to each of the member systems, Minnkota and RUS headquarters in Washington, D.C. All parties have to agree to the revised Work Plan and any deviations from the Work Plan have to be acceptable to all study participants.

7.5 PRS Approach

Economic modeling was the primary forecasting technique utilized in the member systems' PRS. Econometric modeling identifies relationships between energy use and economic, demographic and system trends. The models are based upon 10 years of historical data and utilize such factors as population, employment, income, weather, electricity prices, alternate fuel prices, agricultural economic conditions, as well as other factors pertinent to model development. The studies specifically determined and quantified the factors that historically had impacts on electrical usage.

Econometric models were developed to forecast the number of residential consumers, residential energy usage, the number of small commercial consumers and small commercial usage.

Forecasts for the number of large commercial customers and usage were developed judgmentally, based on input from the member systems or the large commercial customers.

Judgment and trend analysis were utilized to forecast irrigation sales, street lighting, sales to public authorities, sales for resale, own usage and losses for each of the member systems.

Models were developed using the ordinary least squares approach to regression analysis. All of the models and their resulting forecasts were selected on the basis of theoretical and statistical validity and reasonableness of results.

Minnkota's PRS was developed in a bottom-up manner. The individual member system's energy and capacity requirements forecasts were summated to form Minnkota's base forecast. A forecast of Minnkota's transmission losses and its own energy usage, a forecast of the Cavalier Air Force Station energy requirements (based on historical usage) and the forecast of the NMPA energy requirements were then added to the base forecast to obtain the total Joint System energy requirements forecast. The forecast of seasonal (winter and summer) peak demand is based on load factor calculations.

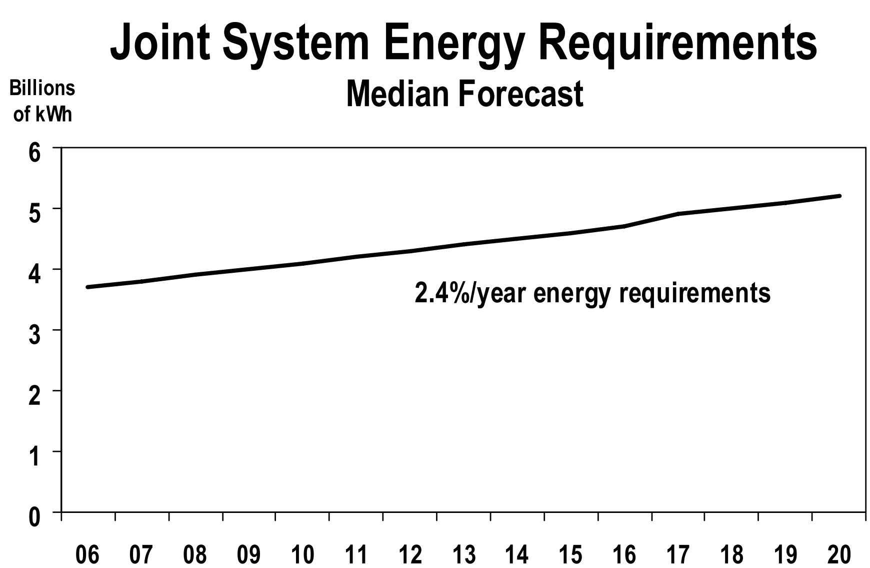
7.6 Median Energy Forecast

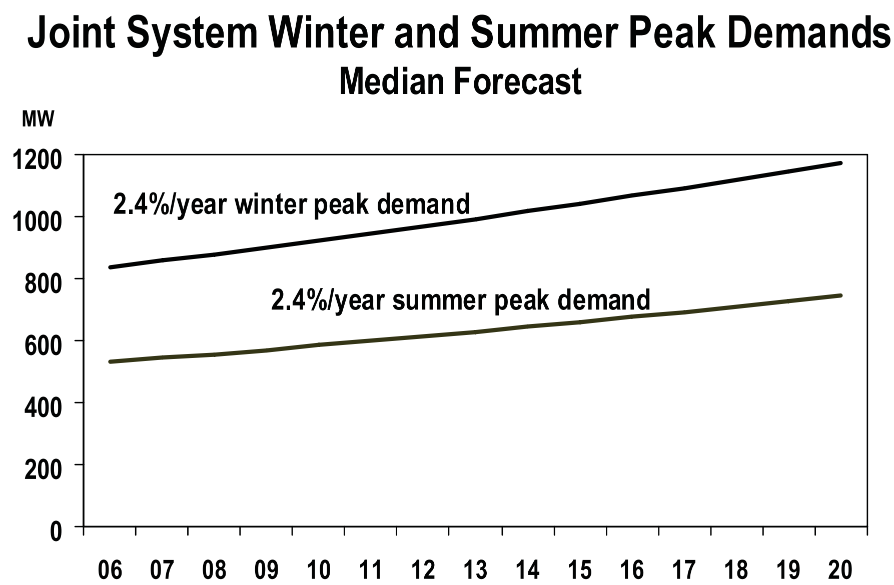
As noted earlier in this section, Minnkota's PRS is the result of the summation of the forecasts of the individual member cooperative's future energy requirements. To this initial energy requirement forecast, an estimate of Minnkota's future transmission losses and own usage were added. Next an estimate of the Cavalier Air Force Station energy requirements (based on historical usage) was added to the total. The last step was to combine Minnkota's total energy requirements and the NMPA energy requirements to develop a comprehensive long-term forecast of the total energy requirements of the Joint System. The forecast of winter and summer peak demands is derived utilizing load factor estimates. Load factor estimates are based on historical data.

The Joint System median forecast of its annual energy requirements, winter peak demands and summer peak demands are shown in the following table:

Year	Annual Energy Requirements MWh	Winter Peak Forecast MW	Summer Peak Forecast MW
2006	3,954,538	836	530
2007	4,073,128	861	546
2008	4,146,197	877	556
2009	4,248,756	898	569
2010	4,359,523	922	585
2011	4,466,766	944	598
2012	4,580,059	968	614
2013	4,694,605	992	629
2014	4,812,122	1,017	645
2015	4,927,613	1,042	661
2016	5,045,876	1,067	676
2017	5,166,977	1,092	692
2018	5,290,984	1,119	709
2019	5,417,968	1,145	726
2020	5,548,000	1,173	744

The above information is graphically displayed in the following charts:





The Joint System's median forecast of total energy requirements projects a 2.4 percent per year increase of the next 15 years. The winter peak demand is projected to increase at a rate of 2.4 percent per year and the summer peak demand is projected to increase at a rate of 2.4 percent per year.

7.7 Bandwidth Energy Forecast

Analysis was done to determine the sensitivity of projected load growth to extreme weather. This work was included in the PRS and has been incorporated into this IRP.

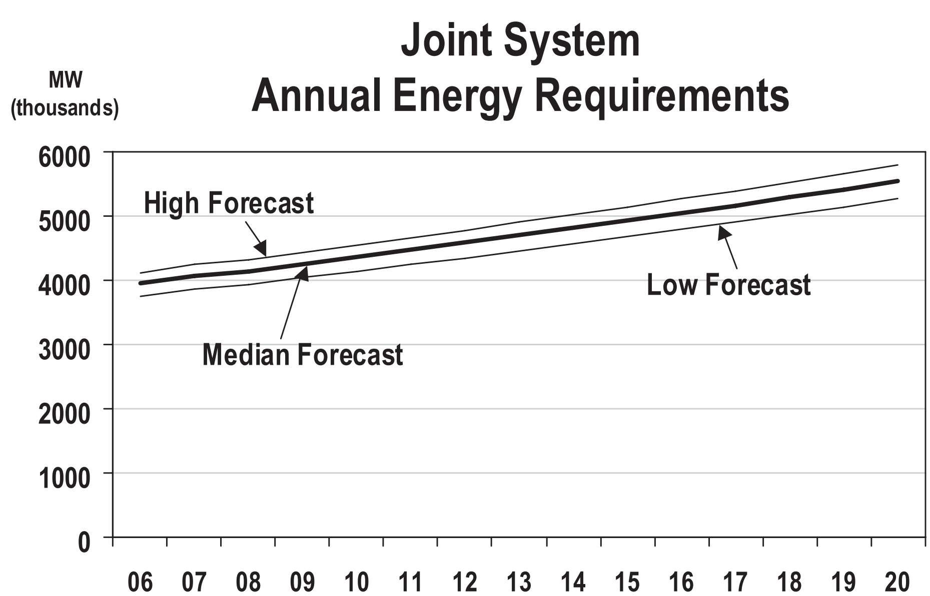
The low load growth scenario was based on the impacts that extremely mild weather would have on the forecast. The high load growth scenario was based on the impacts that extremely harsh weather would have on the forecast.

These two scenarios are the basis for the bandwidth forecasts for the member systems. Although the sensitivity analyses were only studied for the member systems, the same percentage variation was applied to the Joint System energy requirements, since the characteristics of the municipals' electric load is similar to those of the member systems' load characteristics.

The following table lists the Joint System's annual energy requirements for the high, median and low growth scenarios:

Year	Low Growth Forecast Energy Requirements MWh	Median Growth Forecast Energy Requirements MWh	High Growth Forecast Energy Requirements MWh
2006	3,760,334	3,954,538	4,125,940
2007	3,872,026	4,073,128	4,250,318
2008	3,940,853	4,146,197	4,326,942
2009	4,037,061	4,248,756	4,434,969
2010	4,141,339	4,359,523	4,551,169
2011	4,242,158	4,466,766	4,663,791
2012	4,348,529	4,580,059	4,782,958
2013	4,456,168	4,694,605	4,903,290
2014	4,566,446	4,812,122	5,026,937
2015	4,676,041	4,927,613	5,147,583
2016	4,788,266	5,045,876	5,271,125
2017	4,903,184	5,166,977	5,397,632
2018	5,020,860	5,290,984	5,527,175
2019	5,141,361	5,417,968	5,659,827
2020	5,264,754	5,548,000	5,795,663

The following chart graphically depicts the Joint System's annual energy requirements for the low, median and high load growth forecasts from the previous table:

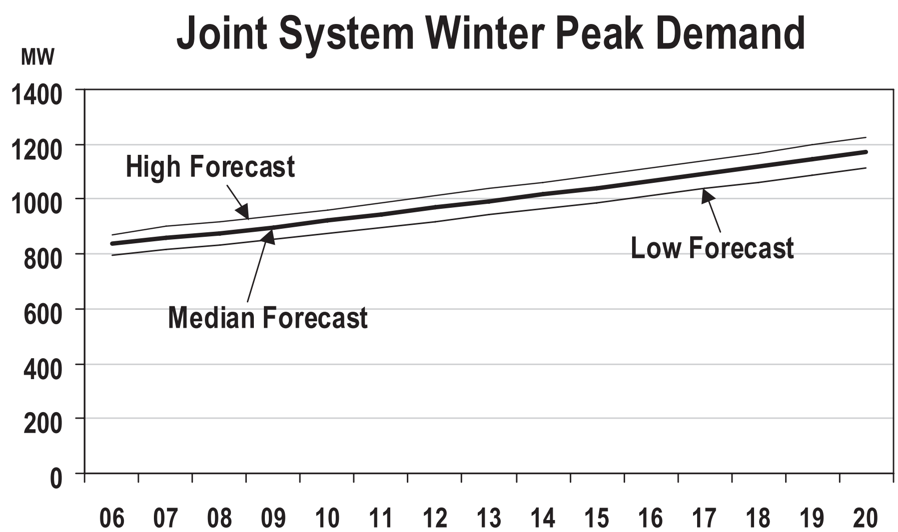


7.8 Winter Peak Bandwidth Forecasts

The following table lists the winter peak demands that were derived from the low, median and high forecasts of the Joint System's future energy requirements:

Year	Winter Peak Low Growth Forecast MW	Winter Peak Median Growth Forecast MW	Winter Peak High Growth Forecast MW
2006	795	836	872
2007	819	861	899
2008	833	877	915
2009	853	898	938
2010	875	922	962
2011	897	944	986
2012	919	968	1,011
2013	942	992	1,037
2014	965	1,017	1,063
2015	989	1,042	1,088
2016	1,012	1,067	1,114
2017	1,037	1,092	1,141
2018	1,061	1,119	1,168
2019	1,087	1,145	1,196
2020	1,113	1,173	1,225

The following chart is a graphic display of the winter peak demands from the previous table:

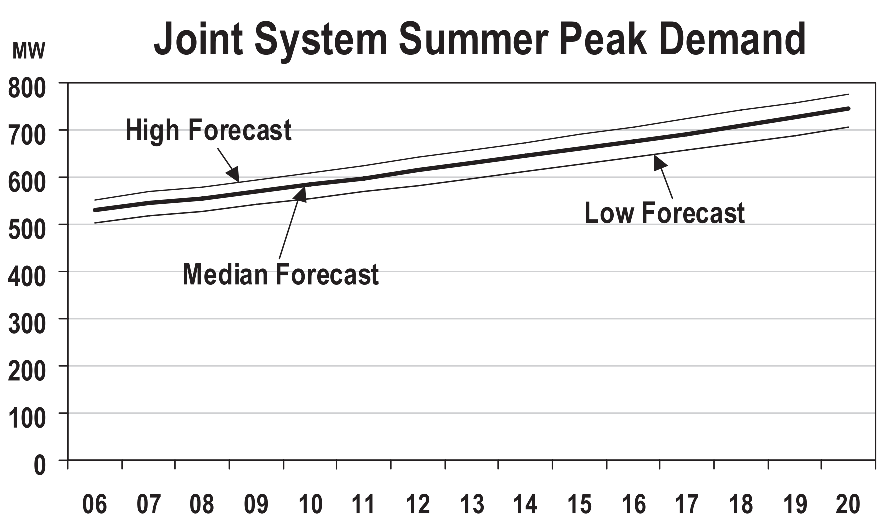


7.9 Summer Peak Bandwidth Forecasts

The following table lists the summer peak demands that were derived from the low, median and high forecast of the Joint System's future energy requirements:

Year	Summer Peak Low Growth Forecast MW	Summer Peak Median Growth Forecast MW	Summer Peak High Growth Forecast MW
2006	504	530	553
2007	519	546	570
2008	528	556	580
2009	541	569	595
2010	555	585	610
2011	569	598	625
2012	583	614	641
2013	597	629	657
2014	612	645	674
2015	627	661	690
2016	642	676	706
2017	657	692	723
2018	673	709	741
2019	689	726	758
2020	706	744	777

The following chart is a graphic display of the summer peak demand from the previous table:



7.10 Integration of Load Management into IRP Process

Minnkota and the member systems, along with the NMPA municipals, have assembled a comprehensive and effective Load Management (LM) Program. Today, approximately 51,000 end-use loads are involved in some way with this program.

The LM Program was initiated in 1973 with dual heating systems as the main focus of the program. In the early years, the main effort was in mitigating winter peak demand growth. However, in the early 1990s the LM program was expanded to include summer load control. At that time, it was realized that summer peak demand growth also needed attention.

In the years since 1973, the member systems and the NMPA municipals have developed a high degree of expertise in determining which end-use loads are adaptable to the LM Program and which ones are not.

7.11 Interruptible Load Development

Based on the last 28 years of operational experience with winter interruptible loads, the following is a forecast of the amount of demand relief that will be realized in future winter peak load periods:

Winter Season	Interruptible Load – MW
2006-07	257
2007-08	260
2008-09	265
2009-10	270
2010-11	275
2011-12	281
2012-13	286
2013-14	291
2014-15	297
2015-16	302
2016-17	307
2017-18	313
2018-19	318
2019-20	324

7.12 Summer Season Interruptible Load Estimates

Based on the last 11 years of operation experience with summer interruptible loads, the following is a forecast of the amount of demand relief that will be realized in future summer peak load periods:

Summer Season	Interruptible Load – MW
2006	48
2007	50
2008	50
2009	50
2010	51
2011	51
2012	52
2013	52
2014	53
2015	53
2016	53
2017	54
2018	54
2019	54
2020	55

7.13 Load and Capability Report

As part of the responsibilities of belonging to MAPP, Minnkota is required to maintain, either by owning generation or by capacity purchases, sufficient generation capacity to serve 115 percent of its annual peak demand. The additional 15 percent is required by MAPP for reserves, which may be needed to serve unexpected load growth or system emergencies. Each member of MAPP has a similar obligation to carry reserves.

However, if a MAPP utility's actual load plus reserve obligation exceeds its net generation capability, then it is required to purchase generation capacity from other MAPP members. The purchase is usually at a much higher rate than if the utility had made its own arrangements prior to becoming deficit. The reason for the stiff penalty is to ensure that adequate and timely generation capacity additions materialize to maintain a high degree of reliability for the end-use customers.

MAPP developed a Load and Capability (L&C) Report to help its members plan their future capacity requirements. The L&C Report is a forecast of the utility's generation, load and reserve requirements. This Report takes into account not only the utility's load and generation, but also sales and purchases. Schedule L purchases are also taken into account in this Report. It is an important planning tool for MAPP utilities, since it aids forecasting the amount of future generation capacity that will be required by taking into account the needed planning reserves.

The Joint System does not complete a L&C Report; only Minnkota does. However, Minnkota does have the responsibility of providing for the future load growth of the NMPA municipals, and therefore must take into account the reserve capacity obligation as well as the load growth of the NMPA. This is done by completing a L&C Report for the Joint System. The Joint System L&C Report is used for internal planning purposes.

Because of the large variations that can occur in peak demand due to weather and the economy, among other things, peak demand forecasting is difficult. With the difficulty in peak demand forecasting and the stiff MAPP penalties for those utilities that are deficit in generation capacity, generation planning at Minnkota tends to be conservative. Conservative generation planning, in this case, means having sufficient generation capacity available to cover unlikely, but possible, peak demand situations. This is especially true for the near term, since it may be extremely difficult to arrange for additional capacity on short notice.

The Joint System Load & Capability Reports for the low, median and high growth forecasts for the winter and summer seasons are included in the following pages of this section. These L&C Reports take into account the Joint System load and generation forecasts as well as the existing and future sales and purchases from other utilities.

The information provided from the L&C Reports helps determine the direction that the Joint System will take in long-term generation expansion planning.

The L&C Reports highlight what the expected surplus/deficit situation of the Joint System will be in the future. The amounts of capacity that the Joint System will be deficit in the future will determine, to a great extent, generation expansion planning.

The following tables document the expected yearly surplus/deficit amounts for the high, median and low peak demand forecasts for the winter and summer seasons:

Winter Season
Surplus/Deficit Amount (MW)

Season	Low Growth	Median Growth	High Growth
2005-06	104	57	15
2006-07	108	60	16
2007-08	119	68	25
2008-09	126	74	28
2009-10	106	52	6
2010-11	86	32	-16
2011-12	68	12	-38
2012-13	47	-10	-62
2013-14	27	-33	-86
2014-15	6	-55	-108
2015-16	-15	-78	-132
2016-17	-38	-101	-157
2017-18	-58	-125	-182
2018-19	-83	-149	-208
2019-20	-106	-175	-234

Summer Season
Surplus/Deficit Amount (MW)

Season	Low Growth	Median Growth	High Growth
2006	64	38	15
2007	52	25	1
2008	64	36	12
2009	72	44	18
2010	56	26	1
2011	40	11	-16
2012	24	-7	-34
2013	7	-25	-53

2014	-10	-43	-72
2015	-28	-62	-91
2016	54	20	-10
2017	37	2	-29
2018	18	-18	-50
2019	-1	-38	-70
2020	-20	-58	-91

7.14 Energy Considerations

In addition to generation capacity deficits, the amount of energy that the Joint System needs to procure from resources not under its control is another important factor in determining long-term generation expansion planning.

The Joint System has a number of generation resources that are comparatively low cost. The Young 1, Young 2 and Coyote generating units are all baseload, low-cost energy resources. In addition, the NMPA WAPA firm power allocation and Minnkota's firm power allocation are also low-cost energy resources. However, the remaining generating resources are mostly old diesel units and are high cost.

However, the Joint System's energy requirements significantly exceed the amounts of energy that its economical generation can produce. This situation only exacerbates with load growth. The following table documents, by winter and summer seasons, the amounts of energy the Joint System requires over and above what its economical units can supply:

Winter Season Statistics

Season	Joint System Energy Requirements MWh	Energy Requirements Above Economical Generation Resources MWh	Percent of Energy Requirements Above Economical Generation Resources %
2005-06	2,599,681	145,842	5.610
2006-07	2,677,704	142,361	5.317
2007-08	2,725,702	126,353	4.636
2008-09	2,793,189	119,559	4.280
2009-10	2,865,963	129,462	4.517

2010-11	2,936,474	161,437	5.498
2011-12	3,010,862	199,066	6.612
2012-13	3,086,197	241,887	7.838
2013-14	3,163,603	290,967	9.197
2014-15	3,239,512	342,686	10.578
2015-16	3,317,260	359,944	10.851
2016-17	3,396,842	416,066	12.249
2017-18	3,478,397	475,927	13.682
2018-19	3,561,887	539,387	15.143
2019-20	3,647,298	606,925	16.640

Summer Season Statistics

Season	Joint System Energy Requirements MWh	Energy Requirements Above Economical Generation Resources MWh	Percent of Energy Requirements Above Economical Generation Resources %
2006	1,345,815	13,917	1.034
2007	1,395,486	10,432	0.748
2008	1,420,501	5,891	0.415
2009	1,455,644	3,791	0.260
2010	1,493,594	7,805	0.523
2011	1,530,359	13,694	0.895
2012	1,569,142	22,695	1.446
2013	1,608,391	34,714	2.158
2014	1,648,674	49,354	2.994
2015	1,688,232	65,213	3.863
2016	1,728,704	4,859	0.281
2017	1,770,163	9,332	0.527
2018	1,812,649	16,166	0.892
2019	1,856,183	26,212	1.412
2020	1,900,702	39,615	2.084

The danger in having to depend on the energy market to supply a significant amount of the Joint System's energy requirements, rather than from its own generation resources, is that the market can be extremely volatile and quite expensive.

There is another inherent danger in relying on the energy market for significant amounts of energy. The inherent danger is that even though the energy may be available from the market, it may not be deliverable because of transmission limitations. There is no guarantee that the transmission required to transport energy from the market to the Joint System will be available when the energy is needed.

In order to insulate its end-use customers from the high cost and volatility of the energy market, the Joint System is evaluating the options it has available to mitigate these potentially devastating impacts of relying on the market to supply significant amounts of its customers' energy requirements.

The Joint System has begun to evaluate its generation resource expansion opportunities, as well as its renewable resource requirements. These efforts are more fully explained in later sections of this report.

SECTION 8

Resource Options

8.1 Introduction

Generating plants are usually classified according to the amount of time that the units will be run. The baseload classification is for those units that operate for the longest periods of time. The annual energy production level (capacity factor) is usually in the range of 60 percent to 95 percent for a baseload unit. The next classification is intermediate, which usually denotes capacity factors in the 10 percent to 60 percent range. The third classification is peaking and applies to generating units whose capacity factors are less than 10 percent.

8.2 Baseload Generation

Baseload generation characteristically has a high installed capital cost and extremely low production cost, which justifies their construction and utilization. These units require the longest construction times and usually require the most permits.

Baseload generators normally have the lowest production cost compared to other resources such as combined cycle or simple cycle turbines.

8.3 Intermediate Generation

Intermediate generation is characterized as similar to baseload generation but with higher production costs. Because the higher production costs are usually lower than peaking units, it makes economic sense to utilize these units for that part of the load curve where resources are needed for longer periods of time and not over just the daily peak period.

Typical intermediate resources could be older coal-fired units that continue to be economical when the run time is short. New intermediate generators tend to be combined cycle combustion turbines.

8.4 Peaking Generation

Peaking generation is usually characterized by low capital cost and high production cost. Peaking units are utilized during a utility's high peak load periods when the run time is short. Peaking units are a good choice for this situation since the amount of energy required from these units is small compared to energy generated from intermediate and baseload units.

8.5 Coal-Fired Generation

Coal-fired generation plants are utilized by most utilities in the United States. The technology is mature and reliable. Typically coal-fired generating units have very high capital costs and lengthy construction timelines, relative to other forms of generation. However, production costs are the lowest, which is the reason that many coal-fired plants are baseload units. Cycling and load-following operations are usually detrimental to the operational economics of these units.

8.5.1 Pulverized Coal Boilers

Pulverized coal boilers were originally designed for larger boiler sizes with higher steam pressure and temperature requirements. These boilers are the most advanced of the solid fuel boilers currently in operation. The pulverized coal boilers have higher boiler efficiencies compared to the older boiler technologies such as stoker and cyclone types. The combustion process requires grinding the coal to a powder, mixing the powder with heated air and discharging the mixture into a boiler firebox, where it is combusted.

Pulverized coal boilers can be operated either in a sub-critical mode (typically 2,600 psi at 1,000 degrees F and lower) or in a super-critical mode (above 3,200 psi at 1,000 degrees F) of steam conditions.

8.5.2 Circulating Fluidized Bed Boilers

Within a fluidized bed boiler, combustion takes place in a suspended bed of particles in the lower section of the boiler. Combustion within the particle bed occurs at a slower rate and lower temperature than in a conventional pulverized coal boiler. Fluidized bed boilers can handle a wider range of fuel types and Btu content than pulverized coal boilers.

8.5.3 Integrated Gas Combined Cycle

Integrated Gasification Combined Cycle (IGCC) is a generation resource that utilizes synthetic gas as its fuel. Synthetic gas is produced in a gasification unit that uses either heavy petroleum residues, coal or biomass as feed-stock. The gasification process uses boilers to produce the synthetic gas. In IGCC applications, exhaust heat from the gasification process is recovered in a heat recovery steam generator and used to produce steam, which is then passed through a steam turbine/generator unit. The synthetic gas is then burned in a combustion turbine/generator with the exhaust heat also recovered by the heat recovery steam generator/turbine system.

8.6 Combustion Turbine

A simple cycle gas turbine consists of a compressor section, combustor and turbine section. Ambient air is compressed in the compressor and mixed with fuel in the combustor section. The combustion products exit the combustor section and expand through the turbine section. Typically, more than 50 percent of the energy produced is consumed by the compressor section. The remaining energy drives an electric generator. Simple cycle turbines are designed to burn either natural gas or fuel oil. Combustion turbine technology is mature, reliable, capital costs are relatively low and construction times are short (about 12-15 months, including permitting). However, their overall operating costs are high and current fuel costs are extremely volatile.

8.7 Combined Cycle Unit

Combined cycle units consist of a simple cycle combustion turbine together with conventional steam production technologies. A combined cycle unit utilizes the exhaust gases from the combustion turbine to produce steam to be used with a heat recovery steam generator. The efficiency of a combined cycle unit is greater than that of a simple cycle combustion turbine since some of the energy in the turbine exhaust is recovered through the use of the steam generator. Combined cycle units have proven to be reliable and the technology is mature. Construction time for a large combined cycle plant is between 24-30 months.

8.8 Renewable Resource Options

Currently there are a limited number of renewable resource options available and their costs and/or operating characteristics are less desirable, from an economic perspective, than most other options for generation additions.

8.8.1 Wind Generation

Wind generation is likely the most cost-effective renewable energy source for North Dakota and Minnesota. The number of wind machines is increasing and the amount of energy produced from wind is on the rise. However, there are a number of concerns associated with wind generation. Since wind is an intermittent resource, its utilization will require the use of other dispatchable resources or purchases to compensate when not enough energy is produced from wind machines.

The intermittent availability of wind resources requires that the utility have additional generation resources or purchases available for use during those periods when wind-generated energy is lacking. The need to install additional non-wind generation to provide energy during those times when wind resources are not producing will add significant costs for the end-use consumers of the Joint System.

8.8.2 Biomass

Biomass is an energy resource derived from organic matter. At the present time, wood wastes and agricultural residues are the major sources of biomass that potentially could be utilized for electrical generation.

However, it appears that the technology to produce electrical energy from either agricultural residues or wood wastes has not matured and therefore is neither reliable nor cost-effective at this time.

SECTION 9

Preferred Resource Plan

9.1 Introduction

Minnkota's load forecast and the resulting analysis for the Joint System energy requirements strongly indicates the need for future generation additions. From both a load and capability analysis (which determines the need for addition capacity needs) and from an energy requirements analysis (which determines the need for additional energy sources), it was concluded that the Joint System should investigate the feasibility of adding a third coal-fired generating plant at the existing Milton R. Young generating station, located near Center, N.D.

The decision to investigate the addition of a third unit was driven by the fact that future energy requirements were of the magnitude that the most reliable, secure and cost-effective long-term solution would be the addition of baseload generation capacity.

9.2 Feasibility Study

In 2004 Minnkota and Minnesota Power retained Burns & McDonnell (B&McD) to conduct a study to determine the feasibility of constructing and operating a third generating plant at the existing Milton R. Young generating station (MRY Station). The MRY Station consists of two coal-fired generating plants. MRY Unit 1 is rated at 250 MW and Unit 2 is rated at 455 MW.

B& McD made a site visit to the MRY Station to assess the ability of the existing site and infrastructure to support a third coal-fired unit. A comprehensive review of the fuel supply and water supply systems was also a part of the site visit and evaluation.

A fuel supply evaluation was also completed to consider several alternatives for a third unit. The first alternative studied was with the new unit using the same coal as the existing two units. The second alternative studied a third unit designed to operate with greater flexibility in coal quality than the coal used by the existing units. The third alternative evaluated a third unit designed to burn waste coal from the mine. The evaluation resulted in the recommendation to utilize the first alternative. Alternative 1 provides the greatest overall fuel blending flexibility for the existing units, as well as a new unit.

Two boiler technologies and two unit sizes for each technology were evaluated in the study. The following boiler technologies and unit sizes were evaluated: 250 MW circulating fluidized bed (CFB), 250 MW pulverized coal (PC), 500 MW CFB, and 500 MW PC.

9.3 Note on Technology Assessment

The 250 MW and 500 MW alternatives were based on a subcritical steam cycle with seven feedwater heaters and steam turbine conditions of 2,520 psi and 1,050 degrees F and a reheat temperature of 1,050 degrees F. Circulating fluidized bed and pulverized coal boilers were considered for both plant sizes. However, due to current size constraints on circulating fluidized boilers of approximately 250 MW, the 500 MW alternative size was based on two 250 MW boilers.

9.4 Summary of Economic Analysis

B&McD prepared a pro forma economic analysis for each of the coal fired alternatives under RUS and IOU financing scenarios. A 20-year economic analysis was prepared based on the estimated capital costs, performance, fuel costs and operating costs for each alternative. The results of the coal-fired alternatives were compared against the estimated costs of a natural gas combined cycle benchmark alternative operated under two different modes.

The first mode operated the unit on a baseload (7x24) basis. The second mode assumes that the combined cycle unit is operated on a peaking (7x16) basis with the balance of off-peak (7x8) energy provided through wholesale purchases at a set price of $20/MWh. Each of the coal-fired alternatives provides substantial savings over a greenfield combined cycle plant operated on a baseload basis (under IOU financing scenarios, 250 MW CFB and PC alternatives result in slightly higher levelized busbar costs than the combined cycle alternative operated on a peaking basis with off-peak power purchases).

In addition, due to very competitive fuel pricing at the MRY Station, an adequate water supply and shared infrastructure savings, a third unit offers favorable busbar power costs when compared to other coal-fired projects.

The 500 MW PC alternatives resulted in the lowest levelized busbar costs for RUS and IOU financing. The RUS and IOU 500 MW PC alternative busbar costs of $32.73 and

$40.81, respectively, are significantly lower than either of the corresponding RUS and IOU natural gas combined cycle alternatives.

Due to the capital-intensive nature of coal-fired generation projects and length of construction, there is capital-cost risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new coal-fired generation plants include the situation in which several U.S. boiler manufacturers are presently in financial distress and the skilled workforce has aged without a significant influx of new construction workers with the required skills and experience. If a number of new coal units began construction within the next decade, the supply of skilled construction workers could be constrained.

9.5 Conclusions and Recommendations

Based upon the results of the feasibility study, a 400-600 MW pulverized coal-fired unit is the most economical generation addition from both an RUS and IOU financing perspective and from a long-term levelized busbar cost projection.

The levelized busbar cost projection is slightly lower than other coal-fired alternatives and is significantly lower than the baseload natural gas combined cycle alternative. The combined cycle combustion turbine utilized as a peaking unit and coupled with off-peak power purchases also had significantly higher busbar costs than the recommended alternative.

Based upon the results of the feasibility study, it has been decided to continue to explore more fully the addition of a third unit at the Milton R. Young Station. At this point in time the Joint System has not committed to constructing a third unit, only to more fully explore all the ramifications of such a decision.

If a 400-600 MW unit were constructed, Minnkota would not be the only owner. At this time it is envisioned that Minnkota's share of the new unit would be approximately 150 MW. The remaining portion of the unit would be owned by other area utilities.

9.6 Future Planning Considerations and Evaluations

Minnkota and the other potential partners need to complete more comprehensive analyses and additional evaluations. The analyses and evaluations will include:

1. A definitive engineering study should be completed to further refine the projected costs of the preferred alternative and include a preliminary engineering study to be used in permitting efforts.
2. Determine the appropriate size of the proposed addition.
3. Identify permitting requirements and potential permitting risks.
4. Determine the appropriate commercial operations date of new unit given that the partners may have different timing requirements.
5. Complete an assessment of the water supply situation and potential infrastructure needs.
6. Identify the appropriate ownership structure for the partners.
7. Complete studies to determine the transmission enhancements that will be required to deliver the output of the plant to the owners' load centers.

SECTION 10

Minnesota Renewable Energy Objective

10.1 Introduction

Minnesota Statute 216B.1691 addresses the Renewable Energy Objective requirements in which each utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its Minnesota retail customers, or the retail members of a distribution utility to which the electric utility provides wholesale electric service, so that:

1) commencing in 2005, at least 1 percent of the electric energy provided to those retail customers is generated by eligible energy technologies;

2) the amount provided under clause (1) is increased by 1 percent each year until 2015;

3) 10 percent of the electric energy provided to retail customers in Minnesota is generated by eligible energy technologies; and

4) of the eligible energy technology generation that is required under clauses (1) and (2), at least 0.5 percent of the energy must be generated by biomass energy technologies by 2010 and 1 percent by 2015.

Eligible energy technology is defined as an energy technology that generates electricity from any of the following renewable energy sources: solar, wind, hydroelectric with a capacity of less than 60 megawatts or biomass; and was not mandated by state law or commission order.

10.2 Minnkota Renewable Energy Resources

10.2.1 Ainsworth Cogeneration Plant

The Ainsworth (formerly Potlatch) cogeneration plant is an 11.174 MW facility located near Bemidji, Minn. This facility utilized approximately 150,000 tons of waste wood per year from an oriented strand board (OSB) manufacturing facility and a lumber mill to produce steam for processing and generating electricity. The electrical output of the cogeneration facility is purchased by Otter Tail Power Company and Minnkota, with each party purchasing 50 percent of the output. In 2005 Minnkota purchased 32,257 MWh from Ainsworth.

10.2.2 Infinity Wind Program

Minnkota has installed two NEG Micron 0.900 kW wind turbines, one near Valley City, N.D., and the other located near Petersburg, N.D. The Valley City wind turbine became operational on January 25, 2002, and the Petersburg wind turbine became operational on July 12, 2002. In 2005 the Valley City unit produced 2,726 MWh and the Petersburg unit produced 2,759 MWh.

10.3 Joint System Renewable Energy Projections

Assuming that the cogeneration plant, the two Infinity wind turbines and the Thief River Falls hydro plant produce approximately the same amount of energy as produced in 2005, and based upon the retail energy sales forecast, the Joint System should fulfill the Minnesota Renewable Energy Objective through 2006.

For the post-2006 time frame, the Joint System is exploring the potential for adding up to 20 MW of wind energy projects. We are currently having discussion with two CBED projects in Minnesota and wind developers who would develop wind projects within Minnkota's service territory. It is Minnkota's preference at this time to purchase wind energy from a developer rather than construct additional wind generation.

SECTION 11

Transmission Planning

11.1 Introduction

Transmission lines are built for four main reasons, which are outlined below:

1) To serve local load
2) To provide outlet for generation resources
3) To maintain or improve transmission system reliability
4) To enable wholesale economic energy transactions between utilities

Because the construction of transmission lines is driven by different needs as outlined above, transmission planning occurs in various venues. Minnkota is responsible for the transmission planning of its 115 kV and 69 kV systems that is required to maintain reliable and economical service to its native load customers. In some instances this planning effort is done entirely by Minnkota. At other times potential transmission additions will have impacts on other area utilities. When this is the case, Minnkota works together with those utilities in a joint transmission planning process to ensure that its transmission projects do not cause problems for others. Joint planning with other area utilities also helps to minimize future facility additions. By incorporating the various needs of the utilities into joint planning studies, the resultant project may be an integrated solution that is less costly and more reliable than the individual additions that would have been built absent joint planning.

11.2 Regional Planning

For transmission projects above 115 kV, Minnkota interacts with a number of regional groups such as the MAPP sub-regional planning groups, the MISO planning groups, the Minnesota Transmission Owners (MTO) group and CapX 2020.

11.2.1 MAPP Transmission Planning

One of the responsibilities contained in the MAPP Restated Agreement is a requirement that the MAPP Regional Transmission Committee develop and approve, on a biennial basis, a coordinated transmission plan for required transmission additions at 115 kV and above for the ensuing 10 years. This plan may integrate the transmission plans developed by individual MAPP members as well as plans developed by the MAPP regional sub-planning groups.

As a MAPP member that owns and operates transmission facilities, Minnkota is required to participate in the MAPP planning process as a member of the Northern MAPP Sub-regional Planning Group.

The objectives of the regional planning process are to avoid the unnecessary duplication of transmission facilities, to identify alternative means for fulfilling the transmission requirements of the MAPP region, and to maintain reliable and economical transmission service.

11.2.2 MISO Transmission Planning

Similar to MAPP's responsibility to oversee coordinated transmission planning, MISO has responsibility to conduct regional transmission planning to ensure the continued reliability and efficient expansion of the transmission system. MISO is required to develop a long-range transmission expansion plan that addresses both short-term and long-term load serving needs and generation interconnections.

Transmission owners that are members of MISO are responsible for developing their own system-specific transmission plans, which are then consolidated by MISO into an integrated overall MISO Transmission Expansion Plan (MTEP). MISO Planning staff incorporates and modifies, if warranted, the plans submitted by the individual MISO transmission owners and sub-regional planning groups and includes generation interconnection requests to develop a regional integrated plan for the orderly and cost-effective expansion of the MISO transmission system. Although Minnkota is not a transmission-owning member of MISO and therefore not a member of the formal MISO planning infrastructure, it is impacted by MISO planning decisions. To the extent warranted, Minnkota interacts with MISO on transmission planning issues that affect the Joint System.

11.2.3 Minnesota Transmission Owners

The Minnesota Transmission Owners (MTO) is an organization of 16 utilities that own or operate high voltage transmission lines within the state of Minnesota. Minnkota is one of the 16 members.

The MTO has responsibility for the Minnesota Biennial Transmission Projects Report. The major purposes of the Report is to inform the public of transmission issues and to facilitate the tracking of proposed solutions to transmission issues.

The report addresses such issues as transmission system interruptions or curtailments, identifies present and reasonable foreseeable future transmission inadequacies, and determines the transmission system enhancements needed to meet the state's renewable energy objective.

The MTO also organizes and conducts transmission planning zone meetings held each year around the state. The purpose of these zone meetings is to inform the public about planning activities and possible new high voltage transmission lines, and to solicit input from the public about transmission projects. Minnkota is involved in the northwest zone transmission planning meetings.

11.2.4 CapX 2020

In 2004 a number of Minnesota utilities initiated a concerted effort to ensure that the transmission system in Minnesota was adequate to serve the increasing demand for electricity and to efficiently plan and construct any required new transmission. The name CapX 2020 refers to Capital Expenditures by the year 2020.

The utilities that are members of CapX 2020 are Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Southern Minnesota Municipal Power Agency and Xcel Energy.

The mission of the CapX 2020 utilities is twofold:

1. Create a joint vision of the required transmission infrastructure needed to meet the increasing demand for electricity in Minnesota and the region.
2. Create an environment that allows the needed infrastructure to be developed in a timely and efficient manner, consistent with public interest.

Although not a member of CapX 2020, Minnkota has been active in many of the working groups and the planning efforts to date and will continue to participate in future planning studies.

SECTION 12

Environmental Information

12.1 Overview

The U.S. Government, state of North Dakota, Minnkota Power Cooperative, Inc., and Square Butte Electric Cooperative have filed a Consent Decree in the U.S. District Court for the District of North Dakota. If approved by the court, the Consent Decree is the successful conclusion of five years of negotiations between the parties over the interpretation of New Source Review requirements.

12.2 Consent Decree Requirements

As a result of the Consent Decree, the following actions will be taken:

1. Installation of Over-Fire Air (OFA) to control nitrous oxides (NO_x) emissions on Young #2 in 2007.
2. Installation of OFA on Young #1 in 2009.
3. Upgrade of the Young #2 sulfur dioxide (SO_2) scrubber to 90 percent removal efficiency in 2010.
4. Installation of an SO_2 scrubber on Young #1 by the end of 2011 with a removal efficiency of 90 percent (if a dry scrubber) or 95 percent (if a wet scrubber).
5. Installation of additional NO_x controls on Young #2 by the end of 2010.
6. Installation of additional NO_x controls on Young #1 by the end of 2011.
7. Commit to the purchase of $5 million (present worth) of wind energy by end of 2009 or installation and operation of $5 million of wind turbines by end of 2012.

SECTION 13

Two-Year Action Plan

The Joint System will take the following actions during the 2007 and 2008 time frames as part of its ongoing efforts in Integrated Resource Planning:

1. A Power Requirements Study (PRS) will be completed for each of the 11 member systems and Minnkota in 2007. The PRS will track the growth in the demand and energy requirements of the member. The 2007 PRS forecasts will serve as a check of the results and conclusions reached in an analysis of the 2005 PRS.
2. Discussions and meetings will continue to take place between the member systems, the NMPA municipals and Minnkota. These meetings will focus on strategies to reduce energy costs to the end-use customers.
3. Minnkota staff will continue to study and forward recommendations to the Minnkota Board of Directors concerning modifications or additions needed in the Wholesale Power Rate Schedule. These efforts will continue to focus on developing a rate philosophy that is fair and equitable to the members and reflects the applicable power supply expenses.
4. Minnkota staff will continue to analyze the cost-effectiveness of integrating demand side management programs and renewable energy resources into the Joint System power supply resource mix.
5. Installation of Over-Fire Air to control nitrous oxides (NO_x) emissions on Young #2 in 2007.
6. Complete a feasibility study for generation expansion by the end of 2006.
7. Develop a plan by the end of 2007 that would expand Minnkota's wind resources by up to 20 MW.

SECTION 14

Five-Year Action Plan

In addition to the activities outlined in the Two-Year Action Plan, the Joint System will take the following actions during the 2009, 2010 and 2011 time frames as part of its ongoing efforts in Integrated Resource Planning:

1. A Power Requirements Study (PRS) will be completed for each of the 11 member systems and Minnkota in 2009 and 2011. These studies will track the growth in the demand and energy requirements of the member systems. The PRS forecasts will be an important and ongoing part of the Integrated Resource Planning process.
2. Minnkota staff will continue to analyze and forward recommendations to the Minnkota Board of Directors on the best methods of promoting and enhancing load management activities.
3. Minnkota staff will continue to analyze the cost-effectiveness of integrating demand side management programs and renewable energy resources into the Joint System power supply resource mix.
4. Future Integrated Resource Plans will be completed as required.
5. Installation of Over-Fire Air on Young #1 in 2009.
6. Upgrade of the Young #2 sulfur dioxide (SO_2) scrubber to affect 90 percent removal efficiency in 2010.
7. Installation of a SO_2 scrubber with a removal efficiency of 90 percent (if a dry scrubber) or 95 percent (if a wet scrubber) by the end of 2011.
8. Installation of additional nitrous oxides (NO_x) controls on Young #2 by the end of 2010.
9. Installation of additional NO_x controls on Young #1 by the end of 2011.
10. Commit to the purchase of $5 million (present worth) of wind energy by end of 2009 or installation and operation of $5 million of wind turbines by end of 2012.

SECTION 15

Contingencies

15.1 Sudden Addition of a Large Load

The sudden unexpected appearance of a new large load is a situation that many utilities face. If this were to occur in the Joint System service territory, Minnkota would most likely arrange the purchase of short-term generation capacity to serve the new load. The purchase would allow Minnkota the necessary time to complete an analysis of the alternatives or options for long-term capacity commitments. Minnkota would utilize short-term capacity purchases rather than prematurely commit to a long-term obligation without having completed a detailed analysis.

15.2 Sudden Loss of a Large Load

The sudden loss of a large load is also a situation that many utilities face. If this would occur to the Joint System, Minnkota would market the energy that normally would have been sold to the large load into the Midwest ISO energy market or to other MAPP utilities.

15.3 Resource Options Available in the Event of Facilities Shutdown

Minnkota would have a limited number of resource options available in the event that it was forced to shut down its lignite generation facilities. Minnkota currently has no surplus generation resources standing idle and ready to be placed into service. In our view, Minnkota's options, upon loss of an existing resource, would be similar to what other utilities have available to them.

The range of options varies with the severity of the shutdown scenario being evaluated. The economic impact (rate increases) to the end-use customer would increase as the severity of the shutdown scenarios increases.

If only one of its lignite-fired generators was shut down for a limited period of time, Minnkota would likely purchase replacement power from neighboring utilities until the unit was returned to service. The cost of replacement power would be determined by the amount of power purchased and by the length of time for which the power had to be secured. Replacement power costs ($/MW of capacity) would increase for greater amounts of capacity, and the energy costs would also increase if replacement power were required for longer periods of time.

If the generator that was shut down had to be replaced with a new coal-fired or gas-fired generator, replacement power would have to be purchased for a longer period of time. The longer time period would make it more problematic for Minnkota to purchase replacement power from other utilities. It is difficult to estimate the likelihood of successfully purchasing replacement power for the length of time needed to install new generation capacity. However, it would take a minimum of one year to install new gas-fired generation and approximately five to seven years for new coal-fired generation.

If all of Minnkota's coal-fired generation were shut down, the financial impact on Minnkota, and consequently the end-use customer, would be disastrous. Minnkota's member cooperatives and their customers would carry the financial burden of the debt service for the shutdown generators, shoulder the costs for replacement power, and at the same time, finance new generation capacity. Many of Minnkota's end-use customers are farmers trying to survive in a depressed farm economy. The additional financial burden associated with a shutdown of generation facilities would potentially drive many of them out of business because farming operations use a relatively large amount of electricity.

SECTION 16

Environmental Costs

In theory, environmental costs are defined as impacts on the environment from electric generation which are not included in utility costs or customer rates. The MN PUC has adopted environmental externality values for selected air emissions, which included carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrous oxide (NO_X), particulate matter 10 microns and less (PM-10) and volatile organic carbons (VOCs).

Electric utilities in Minnesota are required to use the externality values in conjunction with other factors for generation capacity options reviewed or approved by the MN PUC. However, environmental externality values are not to be applied to unit commitment, dispatch or other operating decisions.

Unlike environmental abatement costs (compliance costs, fees, taxes, etc.), environmental externality values do not represent actual direct costs to end-use customers. Results of any environmental externality analyses should be compared with the socioeconomic impacts, project cost payback, net present value or other non-quantifiable impacts and costs.

The MN PUC has required economic analyses be conducted considering environmental externality values, when considering generation options.

At the present time, the Joint System has no firm plans for adding generation capacity. In the future, when the options for additional generation are better defined, Minnkota will complete a more detailed analysis of its capacity options considering the MN PUC's adopted environmental externality values. The analysis would be performed once the need for additional resources has been solidly determined.

SECTION 17

Miscellaneous Topics

17.1 RTO Participation

For a number of years, Minnkota has been analyzing the advantages and disadvantages of joining the Midwest Independent System Operators (MISO) as a transmission owning member. Minnkota is already a MISO market participant, which allows the purchase or sale of energy with MISO.

The decision of whether or not to join an RTO such as MISO is not an easy matter. There are many issues and concerns to consider and the analysis is complicated. The complications in the analysis arise because membership requires the joining entity to take a substantial number of services from MISO that Minnkota currently provides for itself or procures from the Mid-Continent Area Power Pool (MAPP). The sheer number of services required to be secured from MISO and the difficulty in determining the ultimate cost of these services makes the analysis very difficult and uncertain.

To date, Minnkota does not believe that joining an RTO such as MISO will be cost-effective compared to its current membership in MAPP. However, Minnkota will continue to evaluate membership in MISO.

17.2 Real-Time or Time-of-Use Pricing

In Minnkota's view, time-of-use pricing may not necessarily utilize the power supply and transmission resources of Minnkota to the best extent possible because market and transmission conditions can vary substantially from day to day. Generally, pricing schemes associated with time-of-use rates are established on long-term averages, which do not always reflect current conditions. Minnkota believes its pricing methods are superior to time-of-use pricing.

In investigating the cost of implementing real-time pricing, Minnkota found that it is not feasible for the majority of its end-use customers because of the dispersed nature of rural loads. Using current technology, it is cost-prohibitive to supply real-time pricing information to those customers.

Minnkota believes it is giving proper direction and incentive through its Wholesale Power Rate Schedule to promote off-peak loads, which improves the utilization of both generation and transmission facilities. This is accomplished by utilizing a 12-month ratchet for both the winter and summer billing demand charges. In addition, Minnkota utilizes its load management system to minimize power supply costs by interrupting loads rather than purchasing high-priced energy. The existing wholesale power rate structure, in combination with effective load management strategies, encourages economic use of both the power supply and transmission system. Minnkota believes its philosophy has been and will continue to be successful since our customers enjoy one of the lowest wholesale power costs for generation and transmission cooperatives in the country.

17.3 Determining Optimal Level of Demand Side Resources

The three-step approach favored by the Department of Commerce for evaluating load management and conservation options is difficult for Minnkota to adopt. Minnkota is limited in its ability to conduct quantitative demand side management (DSM) analysis because it does not interface directly with end-use customers. In addition, Minnkota has no authority to set DSM goals for the member systems (distribution cooperatives), which actually own Minnkota.

It is Minnkota's belief that DSM is best encouraged by giving the proper rate signals to the end-use customer through the Wholesale Power Rate Schedule. This philosophy allows the member-owner systems and their customers the freedom and flexibility to determine the best manner in which to implement DSM strategies to minimize their overall energy costs.

Because Minnkota's Load Management (LM) Program has a well-defined set of guidelines and rules, employs easily understood and accepted control strategies, and is easily integrated into end-use customers' equipment, its LM Program has been well-received and widely accepted by a large number of consumers. With the large number of consumers involved in the LM Program, with 25 years of LM experience with what works and doesn't work for consumers in the way of controllable loads and strategies, and with the ingenuity shown by both the member-owner systems' staffs and their consumers in implementing new and innovative LM ideas, Minnkota believes that its LM Program fulfills the ultimate goal of the three-step approach.

The ultimate goal of the three-step approach to DSM is the implementation of the most cost-effective DSM strategies available to end-use customers. Minnkota believes that this goal has been overwhelmingly achieved with the success of its LM Program and that the LM Program will continue to achieve this goal for many years into the future.

17.4 MACT Requirements

The Consent Decree requires Minnkota to install an SO_2 scrubber on Young #1 by the end of 2011 and upgrade the SO_2 scrubber on Young #2 to 90 percent removal efficiency in 2010. The additions will reduce SO_2 emissions at the Young Station by approximately 25,000 tons per year.

Additionally, Minnkota will install NO_x removal equipment on Young #1 and Young #2. The additions will be accomplished in two phases. During the first phase, Over-Fire Air equipment will be installed on Young #2 in 2007 and on Young #1 in 2009. The second phase additions will be determined by a Best Available Control Technologies (BACT) study, and installed on Young #2 in 2010 and Young #1 in 2011.

17.5 Renewable Resource Scenarios – 50 percent and 75 percent

The Joint System is planning to add approximately 150 MW of new generation capacity in the 2015 time frame. The 50 percent renewable scenario would require 75 MW of renewable resources and the 75 percent renewable scenario would require 112.5 MW of renewable resources.

The most likely renewable resource would be wind. If you assume that a wind resource has an availability of 35 percent, then 75 MW of renewable resources would require approximately 215 MW of wind generation, and 112.5 MW of renewable resources would require 322 MW of wind generation.

In addition, since wind is very intermittent in Minnesota and North Dakota, and because of the need for certainty of generation resources to serve firm load, the Joint System would also need to install other generation such as gas turbines to serve its firm load during times when wind resources were not producing any energy.

The conclusion is that any resource option requiring either 50 percent or 75 percent renewable resources is extremely more costly than the base case option because of the low availability (35 percent) of the wind resources and the fact that backup generation such as a gas turbine is needed to serve firm load when the wind resources are not producing any energy.

The Joint System does not believe that the 50 percent and 75 percent renewable resource options represent a viable or cost-effective method of meeting its future energy and generation capacity needs.

SECTION 18
Public Participation

Public participation in the integrated resource planning process was provided by the governing boards of the member systems, which represent end-use customers. Their ideas and concerns were solicited as part of the overall resource planning process. Shown below is a list of the dates and locations at which presentations of the draft IRP report were given.

	Date	Location
Beltrami Electric Cooperative	April 26, 2006	Bemidji, MN
Cass County Electric Cooperative	May 30, 2006	Kindred, ND
Cavalier Rural Electric Cooperative	May 31, 2006	Langdon, ND
Clearwater-Polk Electric Cooperative	May 31, 2006	Bagley, MN
Nodak Electric Cooperative	May 9, 2006	Grand Forks, ND
North Star Electric Cooperative	May 10, 2006	Baudette, MN
PKM Electric Cooperative	May 30, 2006	Warren, MN
Red Lake Electric Cooperative	April 26, 2006	Red Lake Falls, MN
Red River Valley Cooperative Power Assoc.	April 24, 2006	Halstad, MN
Roseau Electric Cooperative	May 24, 2006	Roseau, MN
Wild Rice Electric Cooperative	May 30, 2006	Mahnomen, MN
Minnkota Power Cooperative, Inc.	June 30, 2006	Grand Forks, ND

At these meetings, individual members of the Board of Directors of the member systems were given the opportunity for participation in the IRP process and their input, ideas and comments were solicited and received. Their board resolutions are included in Appendix A.

Since Minnkota's Board of Directors June meeting is on the 30th, there will not be sufficient time to include Minnkota's Board resolution in the 2006 IRP. Copies of the Board resolution will be available upon request.

SECTION 19

Plan is in the Public Interest

19.1 Maintain or Improve the Adequacy of Utility Service

The Joint System 2006 Integrated Resource Plan (2006 IRP) maximizes the use of existing resources by maintaining and extending the useful life of its assets where it is practical and economically justifiable.

19.2 Keep Customers' Bills and Utility Rates as Low as Practical, Given Regulatory and Other Constraints.

The 2006 IRP documents how the Joint System will evaluate all resource options and select those that are the most cost-effective.

19.3 Minimize Adverse Socio-Economic Effects and Adverse Effects Upon the Environment.

The Joint System intends to meet any federal and state environmental requirements. This goal is implicit in the 2006 IRP.

19.4 Enhance the Utility's Ability to Respond to Changes in the Financial, Social and Technological Factors Affecting its Operations.

The Joint System recognizes the need to be flexible in matters concerning these factors. This flexibility is evident in that the Joint System has its generation resources diversified into three different baseload plants, has a well-established and extensive load management program, has numerous transmission ties with various area utilities, is a Midwest Independent System Operator (MISO) market participant, and is exploring various options for future generation additions. The Joint System will continue to maintain flexibility in those areas that affect its ability to serve its customers in a cost-effective manner.

19.5 Limit the Risk of Adverse Effects on the Utility and its Customers from Financial, Social and Technological Factors that the Utility Cannot Control.

The Joint System is mindful of the many risks that the electric industry faces. It is continually evaluating those risks as it analyzes the various generation options that are presently available. It is also evaluating the advantages, disadvantages and risks involved in becoming a member of a regional transmission organization such as MISO. The 2006 IRP outlines the concerns about these risks and discusses how the risks may be avoided or minimized.

19.6 Summary.

The Joint System 2006 IRP fulfills the requirements or Minnesota statutes and rules. It presents a clear and concise picture of how the Joint System intends to satisfy the electrical requirements of its customers in a cost-effective and reliable manner while meeting federal and state environmental requirements.

SECTION 20

Cross Reference Guide

20.1 Cross Reference of Resource Plan Requirements

Rule or Statute		**Reference Section**
216B.1691 Subdivision 2	Report on plans, activities, and progress with regard to the renewable energy objectives.	10
216B.2422 Subdivision 2	Include least-cost plans for meeting 50 percent and 75 percent of all new and refurbished capacity needs with conservation and renewable energy.	17
Subdivision 3	Utility must use the environmental cost values, along with other socioeconomic factors, in selecting resources.	16
Subdivision 6	Utility should state if it intends to site or construct a large energy facility.	2
7843.0300 Subparagraph 5	Submit 15 copies of the plan to the Commission, and copies to the Department, Attorney General, MEQB and other interested parties.	See Service List
7843.0400 Subparagraph 1	Include a copy of the latest advance forecast to the DOC and MEQB.	Appendix A
Subparagraph 3	Include a list of resource options considered.	8
Subparagraph 3	Description of the process and analytical techniques used in developing the plan.	7
Subparagraph 3	Include a five-year action plan with a schedule of key activities and regulatory filings.	14
Subparagraph 3	Include a narrative of why the plan is in the public interest.	19
Subparagraph 4	Include a non-technical summary not to exceed 25 pages in length.	2
Notice May 28, 1996	Submit an original copy of the filing as an unbound, one-sided document on 8½ x 11 inch paper with no tabbed dividers.	Enclosed With PUC Filing

20.2 Cross Reference to Commission's Order on 2002 Integrated Resource Plan (ET-6, 6132/RP-02-1145)

		Section
A.	Minnkota will set up and include in its next filing a chart cross-indexing rule requirements and sections that address those requirements; this will aid Minnkota in preparing a complete filing and would speed the completeness review;	20
B.	Minnkota will provide an update on whether it actually has exercised options on Square Butte and whether it will continue to do so in future years;	4
C.	Minnkota will include a discussion of its ability to meet Minn. Stat. 216B.1691;	10
D.	Minnkota will discuss its potential affiliation with a regional transmission organization in the future and detail any effects that regional transmission organizations have on the Cooperative's transmission planning process;	17
E.	Minnkota will continue to examine the use of time-of-day or real-time pricing as an additional demand-side resource;	17
F.	Minnkota will consider determining the optimal level of demand-side resources if it needs to construct generation or transmission in Minnesota in the near future;	17
G.	Minnkota will work with its member systems and NMPA to determine energy and demand savings attributable to conservation efforts; and	Complete
H.	Minnkota will explain more fully how the MACT requirements could affect the Joint System.	17

20.3 Cross Reference to 2002 Integrated Resource Plan Two-Year Action Plan

		Section
A.	A Power Requirements Study (PRS) will be completed for each of the 11 member systems and Minnkota in 2003. The PRS will track the growth in the demand and energy requirements of the member systems. The 2003 PRS forecasts will serve as a check of the results and conclusions reached in an analysis of the 2001 PRS.	Completed
B.	Discussions and meetings will continue to take place between the member systems, the NMPA municipals and Minnkota. These meetings will focus on strategies to reduce energy costs to the end-use customers.	Ongoing
C.	Minnkota staff will continue to study and forward recommendations to the Minnkota Board of Directors concerning modifications or additions needed in the Wholesale Power Rate Schedule. These efforts will continue to focus on developing a rate philosophy that is fair and equitable to the members and reflects the applicable power supply expenses.	Ongoing
D.	Minnkota staff will continue to analyze the cost effectiveness of integrating demand side management programs and renewable energy resources into the Joint System power supply resource mix.	Ongoing
E.	In 2003, exercise the Square Butte generation capacity option for 2006.	Completed
F.	In 2004, exercise the Square Butte generation capacity option for 2007.	Completed

20.4 Cross Reference to 2002 Integrated Resource Five-Year Action Plan

		Section
A.	A Power Requirements Study (PRS) will be completed for each of the 11 member systems and Minnkota in 2003 and 2005. The PRS will track the growth in the demand and energy requirements of the member systems. The PRS forecasts will be an important and ongoing part of the Integrated Resource Planning process.	Completed
B.	Minnkota staff will continue to analyze and forward recommendations to the Minnkota Board of Directors on the best methods of promoting and enhancing load management activities.	Ongoing
C.	Minnkota staff will continue to analyze the cost effectiveness of integrating demand side management programs and renewable energy resources into the Joint System power supply mix.	Ongoing
D.	Future Integrated Resource Plans will be completed as required.	Ongoing
E.	In 2005, exercise the Square Butte generation capacity option for 2008.	Will Be Exercised
F.	In 2006, exercise the Square Butte generation capacity option for 2009.	Will Be Exercised

APPENDIX A

Minnesota Electric Utility Annual Report

APPENDIX B

Minnesota Electric Utility Information Reporting-Forecast Section

APPENDIX C

Minnkota Power Cooperative's 2005 Power Requirements Study

APPENDIX D

Governing Boards' Resolutions Approving IRP

MINNESOTA
SERVICE AREA MAP

RUS FORM 12

FORM EIA-861

Minnkota Power Cooperative, Inc.
WHOLESALE POWER RATE

Minnkota Power
MPC COOPERATIVE, INC.
Your Touchstone Energy® Partner

1822 Mill Road
P.O. Box 13200
Grand Forks, ND 58208-3200
Phone: (701) 795-4000

For further information, contact Dale Sollom

Northern Municipal Power Agency

310 Red Lake Blvd.
P.O. Box 485
Thief River Falls, MN 56701-0485
Phone: (218) 681-0963