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

June 26, 2014

Dr. Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of MInnkota Power Cooperative, Inc.'s 2014 Resource Plan; ET6-RP-14-526

Dear Dr. Haar,

Minnkota Power Cooperative, Inc., a Minnesota cooperative corporation, respectfully files this 2014 Resource Plan for review and acceptance. This Resource Plan is filed pursuant to Minn. Stat. § 216B.2422 and Minn. Rules Ch. 7843. This filing complies with the Commissioner's Order in our previous resource plan proceeding, Docket No. ET2/RP-10-782.

This Resource Plan covers the forecast period of 2014 – 2028, and outlines Minnkota's plan to meet our member distribution cooperatives' energy needs in an affordable and reliable way.

We respectfully request the Commission accept this Resouce Plan, pursuant to Minn. Stat. § 216B.2422, subd. 2. Please contact me a 701-795-4219 or jovergaard@minnkota.com should you have any questions concerning this filing.

Sincerely,

/s/ Jamie Overgaard

Jamie Overgaard
Rates, Load & Planning Manager
Minnkota Power Cooperative, Inc.
1822 Mill Rd
Grand Forks, ND 58203

C: Service List

STATE OF MINNESOTA

BEFORE THE PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
Dan Lipshcultz	**Commissioner**
Betsy Wergin	**Commissioner**

In the Matter of the 2014 Resource Plan of Minnkota Power Cooperative, Inc.

Docket No. ET6-RP-14-526, **Initial Filing**

CERTIFICATE OF SERVICE

I, Stacey Dahl, hereby certify that I have this day served a copy of the following, or a summary thereof, on Dr. Burl W. Haar by e-filing and to all other persons on the attached service list by electronic service.

Minnkota Power Cooperative, Inc.
2014 Resource Plan

Date this 26^{th} day of June, 2014

/s/ STACEY DAHL

Stacey Dahl
Minnkota Power Cooperative, Inc.
1822 Mill Rd
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Minnkota Power Cooperative, Inc.

– and –

Northern Municipal Power Agency

2014 INTEGRATED RESOURCE PLAN

2014 – 2028

Submitted to the

Western Area Power Administration

– and the –

Minnesota Public Utilities Commission

Minnkota Power
MPC COOPERATIVE, INC.
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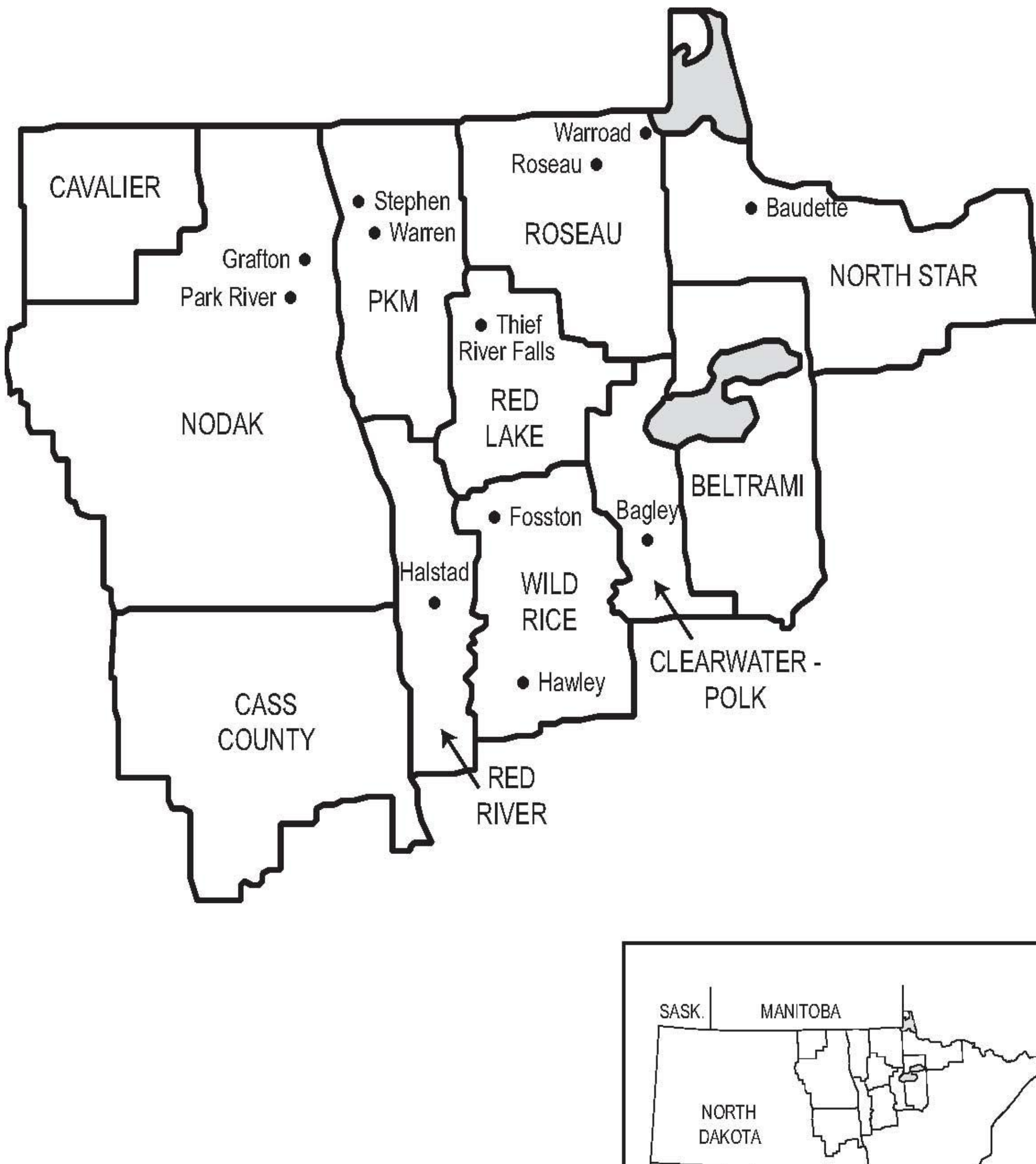
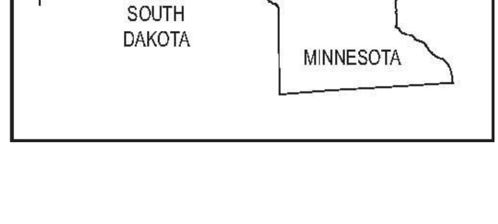
Northern Municipal Power Agency

SERVICE AREA





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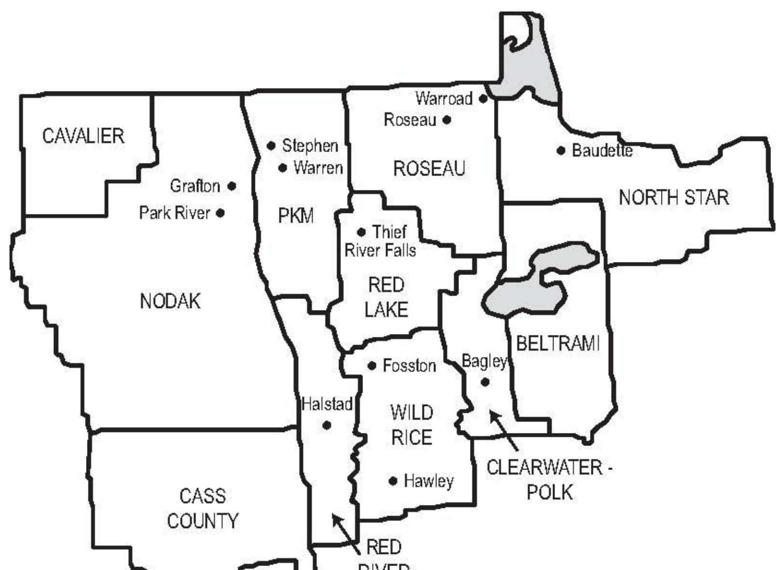
SECTION 1
Introduction

1.1 Minnkota Power Cooperative, Inc.

Minnkota Power Cooperative, Inc. (Minnkota) is a wholesale electric generation and transmission cooperative formed on March 28, 1940, and headquartered in Grand Forks, N.D. 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, 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 Dec. 31, 2055, 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, at least 95% of the members' electrical capacity and energy requirements. The members may elect to purchase up to 5% of their requirements from sources other than Minnkota.

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 an Indenture, dated as of June12, 2014, 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, Minn. 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% share of the Coyote generating plant, a 427 MW facility located near Beulah, N.D. NMPA also owns a 15% 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 may 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 similar Wholesale Power Rate Schedules.

1.7 Management and Administration

Minnkota is operated by approximately 368 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 198 employees operate out of the general headquarters in Grand Forks, N.D. Approximately 170 are employed at the Milton R. Young Station located near Center, N.D.

1.8 Market Participant Membership in the Midcontinent Independent System Operator's Energy Market

Minnkota is a market participant in the Midcontinent 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.

SECTION 2
Resource Plan Summary

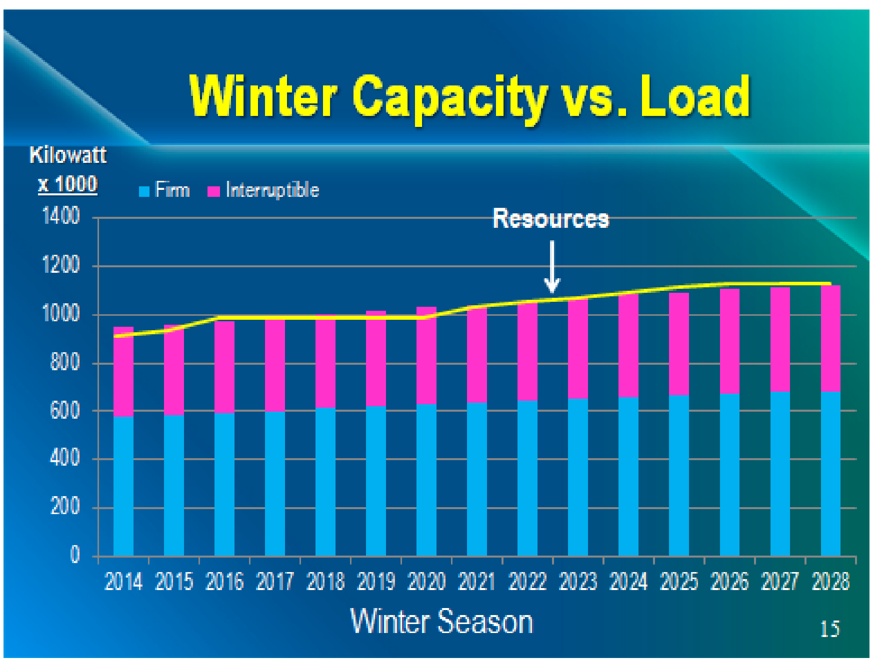
2.1 Introduction

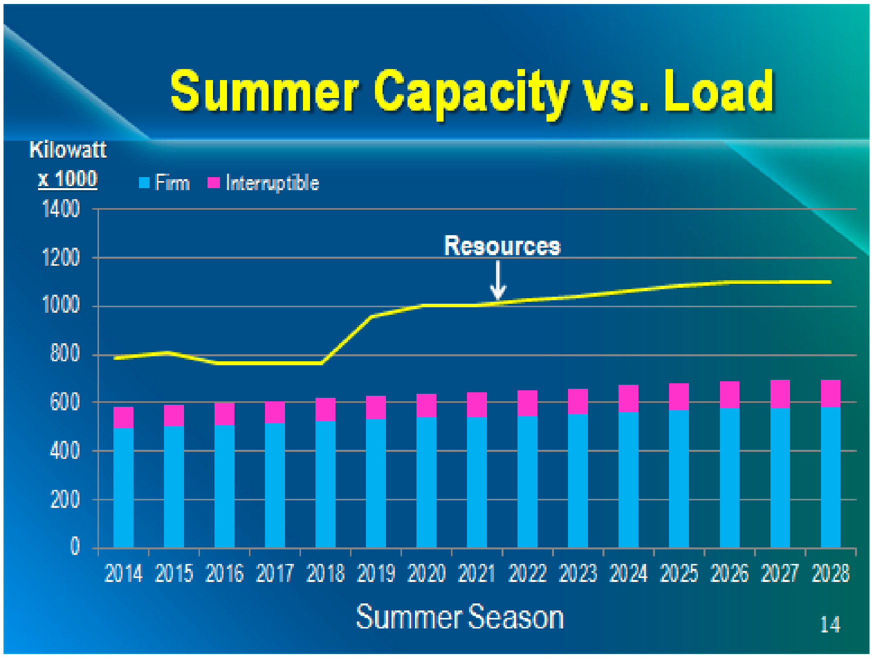
Minnkota and NMPA together submit this 2014 Integrated Resource Plan (IRP). This document has been prepared to fulfill the IRP requirements of WAPA and the Minnesota Public Utilities Commission.

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 Joint System energy requirements are forecasted to increase at a rate of 1.2% per year. The summer and winter peak demands are also forecasted to increase at a rate of 1.0% and 1.1% respectively per year. This is based on the 30 year projections from the 2013 Load Forcast Study. 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. For purposes of illustration, capacity resources are the Joint System generation plants plus the WAPA firm power allocations plus power purchases minus power sales.





As seen from the above tables, the Joint System has more than sufficient resource capacity to serve its firm load during the next 15 years.

2.3 Energy Considerations

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

The Joint System has a number of energy resources. The Young 1, Young 2, and Coyote generating units are all baseload generation. The Joint System also utilizes Minnkota's firm power allocation and the NMPA firm power allocations from WAPA to fulfill its energy requirements. Minnkota also has a number of purchase power agreements for wind-derived energy.

The majority of the Joint System's future energy requirements will be supplied from the resources listed above. The energy requirements not fulfilled by the Joint System's resources will most likely be purchased from the MISO energy market.

From an analysis of the forecasted Joint System energy requirements and the expected output of its generation resources, WAPA firm power allocations, and wind purchase power agreements, it is forecasted that the Joint System purchases from the MISO energy market will range from a low of 0.2% to a high of 5.4% of its total annual energy requirements.

Since the amounts of energy forecasted to be purchased from the MISO energy market are minor, there is no need for additional generation additions from an energy supply perspective. A more detailed explanation of projected MISO energy purchases can be found in Section 7.

2.4 Summary

From both a resource capacity perspective and an energy requirements perspective, the Joint System does not need additional generation resources in the 2014-2028 time frame.

SECTION 3
Demand Response Program

3.1 Historical Perspective

Beginning in 1973, Minnkota and the member systems instituted a comprehensive and effective Demand Response (DR) program. Currently about 55,000 end-use consumers participate in this important program. Due to the large amount of electric heating loads, Minnkota's DR program started with dual heating systems as the main focus of its effort.

3.2 Interruptible Loads

Minnkota's and the member systems' philosophy is to develop interruptible loads in such a manner that the DR program causes as little inconvenience as possible to 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.

The member systems have developed a high degree of expertise in determining what end-use loads are adaptable to the DR program, and which ones are not. Today, for the winter season, the DR program utilizes, in addition to dual heating systems, water heaters, slab storage heating, thermal storage heating, and miscellaneous loads.

Based on the 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
2014	370
2015	375
2016	380
2017	385
2018	390
2019	395
2020	400
2021	405
2022	410
2023	415
2024	420
2025	425
2026	430
2027	435
2028	440

3.3 Summer Season Demand Response

In the mid-1990s, Minnkota extended its DR program to include the summer season. This was done to offset increasing costs brought about by growing summer load growth and increasing generation expansion costs.

Currently, for the summer season, the DR program utilizes large capacity water heaters, irrigation systems, low temperature grain drying, loads with generator backup, and miscellaneous loads.

Based on operational 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
2014	88
2015	90
2016	92
2017	94
2018	96
2019	98
2020	100
2021	102
2022	104
2023	106
2024	108
2025	110
2026	112
2027	114
2028	116

SECTION 4
Existing Resources, Purchases, and Sales

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 resources consist of baseload, diesel, hydro allocations, biomass, and wind generation.

Minnkota and eight of the NMPA municipals have firm power allocations from WAPA. These firm power allocations supply 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) was built and is operated and maintained by Minnkota. Young 1 is a 250 MW lignite-fired mine-mouth generator located approximately seven miles southeast of Center, ND.

4.2.2 MILTON R. YOUNG UNIT 2

Milton R. Young Unit 2 (Young 2) is a 455-MW lignite-fired mine-mouth generator also located approximately seven miles southeast of Center, ND.

4.2.3 COYOTE PLANT

The Coyote Plant is a 427 MW generating plant located southwest of Beulah, N.D., and operated by Otter Tail Power Company. NMPA owns a 30 percent share (128.1 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 LANGDON WIND PROJECT

The Langdon Wind Project is comprised of two separate wind farms located near Langdon, N.D.

The first wind farm, Langdon I, consists of 106 turbines, of which 79 are owned by NextEra and 27 are owned by Otter Tail Power Company (OTP). The turbines are 1.5 MW General Electric machines with a total capacity of 159.0 MW. OTP owns 40.5 MW and NextEra owns 118.5 MW of the turbine capacity of Langdon I. Minnkota has a long-term power purchase agreement with NextEra for 99 MW of capacity and energy.

The second wind farm, Langdon II, consists of 27 turbines, all of which are owned by NextEra. These turbines are also 1.5-MW General Electric machines with a total capacity of 40.5 MW. Minnkota has a long-term power purchase agreement with NextEra for all the capacity and energy produced by Langdon II.

4.2.5 ASHTABULA WIND PROJECT

The Ashtabula Wind Project is comprised of two separate wind farms located near Pillsbury, N.D.

The first wind farm, Ashtabula I, consists of 131 turbines, of which 99 are owned by NextEra and 32 are owned by OTP. The turbines are 1.5 MW General Electric machines with a total capacity of 196.5 MW. NextEra owns 148.5 MW of the turbine capacity of Ashtabula I. Minnkota has a long-term power purchase agreement with NextEra for 148.5 MW of capacity and energy.

The second wind farm, Ashtabula II, consists of 113 turbines, of which 80 are owned by NextEra and 33 are owned by OTP. These turbines are also 1.5 MW General Electric machines with a total capacity of 169.5 MW. NextEra owns 120.0 MW and OTP owns 49.5 MW of the turbine capacity of Ashtabula II. Minnkota has a long-term power purchase agreement with NextEra for the output of 69.0 MW of capacity and energy.

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 Jan. 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 owns and operates 10 diesel generating units. These generators are located at three substations with in the Cass County territory and are the financial responsibility of Cass County. The 10 diesel generators have a total capacity rating of 18.28 MW. Minnkota also purchases the capacity and energy from three of Cass County's customer-owned generators that have capacity ratings of 2.0 MW, 0.9 MW and 0.8 MW.

4.2.9 NMPA Diesel Generation

Three of the NMPA municipal members, Thief River Falls, Grafton, and Halstad, have diesel generators leased to Minnkota. The total capacity of these NMPA diesel generators is 13.536 MW.

4.3 Purchases

4.3.1 WAPA Firm Power Allocation to Minnkota

Minnkota has a Firm Power Allocation from WAPA. This allocation provides firm capacity and energy to the Joint System of 72.632 MW and 358,312 MWh per year.

4.3.2 WAPA Firm Power Allocation to the NMPA Municipals

Eight of the 12 NMPA municipals have a WAPA Firm Power Allocation. These allocations provide firm capacity and energy to the Joint System of 33.639 MW and 174,660 MWh per year.

4.3.3 Fargo Landfill Gas Facility

Minnkota purchases the electrical output from the Fargo, ND, landfill gas facility, which has a capacity of 0.925 MW.

4.3.4 FOSSTON MUNICIPAL SOLID WASTE FACILITY

Minnkota purchases the electrical output from the Polk County solid-waste-fuel generator located in Fosston, MN, which is a capacity of 0.4 MW.

4.4 Sales

4.4.1 MINNESOTA POWER SALES

Minnkota has a sales agreement with Minnesota Power for the following amounts of capacity from the Young 2 generator.

2014 Annual	125 MW
2015 Annual	100 MW
2016 Annual	100 MW
2017 Annual	100 MW
2018 Annual	100 MW
2019 Annual	100 MW
2020 Annual	100 MW
2021 Annual	100 MW
2022 Annual	80 MW
2023 Annual	60 MW
2024 Annual	40 MW
2025 Annual	20 MW

4.4.2 BASIN ELECTRIC POWER COOPERATIVE SALES

Minnkota has a sales agreement with Basin Electric Power Cooperative for the following amounts of capacity.

2014 Annual	50 MW
2015 Annual	50 MW
2016 Summer	200 MW
2017 Summer	200 MW
2018 Summer	200 MW

4.4.3 XCEL ENERGY SALES

Minnkota has a sales agreement with Xcel Energy for the following amounts of capacity from the Joint System's share of the Coyote generator.

2014 Summer	100 MW
2015 Summer	100 MW

4.4.4 ADDITIONAL MP SALES

Minnkota has a sales agreement with Minnesota Power for the following amounts of capacity from the Joint System:

2014	Annual	50 MW
2015	Annual	50 MW
2016	Annual	50 MW

2017	Annual	50 MW
2018	Annual	50 MW
2019	Annual	50 MW
2020	Winter	50 MW

4.5 Transmission Facilities

Minnkota's transmission facilities consist of 214 miles of 345 kV, 443 miles of 230 kV, 265 miles of 115 kV and 2,138 miles of 69 kV lines. Additionally, Minnkota will be completing a 250 mile 345 kV transmission line between Center, ND and Grand Forks, ND in the summer of 2014.

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 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 with neighboring companies.

SECTION 5
Load Forecast

5.1 Overview

The primary function of the 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 sixth IRP that Minnkota Power Cooperative, Inc. and NMPA have filed jointly with the Minnesota Public Utilities Commission under MN Statute 216B.2422 and MN Rules Part 7843.

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 Study

Rural Utilities Service (RUS) defines a Load Forecast Study (LFS) 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 LFS of a power supply borrower includes and integrates the LFSs of its member systems." The LFS 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 LFS.

5.4 LFS Approach

Economic modeling was the primary forecasting technique utilized in the member systems' LFS. Econometric modeling identifies relationships between energy use and economic, demographic and system trends. The models are based upon 30 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.

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.

5.5 Load Forecast

The Joint System load forecast is comprised of the Minnkota Load Forecast 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 Load Forecast Study (LFS). The LFS is on a two-year cycle, meaning that new studies of the individual member-owners and Minnkota are completed every other year. The latest LFSs were completed in 2013.

Minnkota's LFS 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 was also developed.

The municipal members of the NMPA are not required to complete a LFS. However, a load forecast utilizing a linear regression analysis of the historical period 1995 through 2012 was completed for each of the members of the NMPA.

The forecast of the Joint System's energy requirements is the sum of the forecasts of Minnkota's energy requirements, NMPA energy requirements, and transmission losses. The forecasts of the winter and summer peak demands are based on historical trending.

5.6 Joint System Median Annual Energy Requirements, Winter Peak, and Summer Peak Forecasts

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

Median Load Growth Forecasts

Year	Energy Requirements MWH	Winter Peak MW	Summer Peak MW
2014	4,472,405	950	582
2015	4,531,493	960	589

2016	4,614,746	974	599
2017	4,692,422	988	608
2018	4,780,033	1,004	619
2019	4,846,941	1,015	627
2020	4,919,390	1,028	636
2021	4,986,930	1,040	644
2022	5,066,455	1,055	653
2023	5,141,313	1,068	662
2024	5,212,585	1,081	671
2025	5,277,324	1,093	678
2026	5,346,105	1,105	687
2027	5,396,556	1,114	693
2028	5,449,431	1,123	699

The Joint System's median forecast of annual energy requirements is projected to increase a rate of 1.2% per year . The winter peak demand is projected to increase at a rate of 1.0% per year and the summer peak demand is projected to increase at a rate of 1.1% per year. These numbers are based on the 30 year projections from the 2013 Load Forecast Study.

5.7 Joint System Annual Energy Requirements, Winter Peak Demand, and Summer Peak Demand Forecast Bandwidths

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 LFS and has been incorporated into this IRP.

The low load growth scenario was based on the impacts that pessimistic economic conditions would have on the forecast. The high load growth scenario was based on the impacts that optimistic economic conditions would have on the forecast. Economic conditions were 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 annual energy requirements, since the characteristics of the municipals' electric load are similar to those of the member systems' load characteristics.

The forecasts of the Joint System's annual energy requirements, winter peak demands, and summer peak demands for the low load scenario are shown in the following table:

Low Load Growth Forecasts

Year	Energy Requirements MWH	Winter Peak MW	Summer Peak MW
2014	4,339,686	925	566
2015	4,358,385	928	569
2016	4,399,040	933	574
2017	4,429,451	938	578

2018	4,470,187	945	583
2019	4,493,739	948	586
2020	4,520,475	952	589
2021	4,542,518	956	592
2022	4,580,454	962	596
2023	4,613,617	967	600
2024	4,643,088	972	603
2025	4,666,933	976	606
2026	4,692,983	980	609
2027	4,703,707	981	610
2028	4,715,871	982	612

The Joint System's low load growth scenario forecasts an increase of 0.79% per year for annual energy requirements. The winter peak demand is forecasted increase at a rate of 0.3% per year and the summer peak demand is forecasted to increase at a rate of 0.4% per year.

The forecasts of the Joint System's annual energy requirements, winter peak demands, and summer peak demands for the high load growth scenario are shown in the following table:

High Load Growth Forecasts

Year	Energy Requirements MWH	Winter Peak MW	Summer Peak MW
2014	4,596,800	973	595
2015	4,698,077	991	608
2016	4,829,367	1,019	626
2017	4,957,294	1,042	642
2018	5,095,900	1,068	659
2019	5,211,557	1,089	673
2020	5,336,252	1,112	688
2021	5,457,209	1,134	702
2022	5,680,093	1,181	732
2023	5,805,663	1,204	747
2024	5,928,673	1,227	761
2025	6,045,722	1,249	775
2026	6,169,616	1,271	790
2027	6,273,401	1,290	803
2028	6,381,265	1,310	816

The Joint System's high load growth scenario forecasts an increase of 2.0% per year for annual energy requirements. The winter peak demand is forecasted to increase at a rate of 1.8% per year and the summer peak demand is forecasted to increase at a rate of 1.9% per year.

SECTION 6
Resource Adequacy

6.1 Discussion

Minnkota is a load serving entity within the MISO area of operations. As such, Minnkota is obligated to conform to MISO's Resource Adequacy requirements. A reliable bulk electric system requires, among other things, that generation capacity exceeds customer demand by an adequate margin. The margins necessary to insure adequate reliability are assessed on a near-term (operational) basis and on a longer-term (planning) basis.

The focus of Resource Adequacy is on the longer-term planning margins that are required to provide sufficient generating resources to reliably serve customer demand in the planning horizon. Planning reserve margins must be sufficient to cover the following situations:

1) Planned generator maintenance;
2) Unplanned of forced outages of generating equipment;
3) Reductions in generation capacity due to operational problems;
4) Uncertainty in demand forecasts;
5) Outages of transmission lines and other electrical equipment; and
6) Anticipated variations in weather patterns

MISO determines the amount of Minnkota's planning reserve margin on an annual basis. This determination takes into account Minnkota's demand forecasts, its generation resources, and any transactions. Minnkota is required to meet MISO's planning reserve obligations and failure to meet such obligations will result in charges assessed to Minnkota.

SECTION 7
Energy Requirement Considerations

7.1 Introduction

Another important consideration in generation planning is the degree to which the Joint System will be dependent on market-based resources to meet its load requirements.
The Joint System has the Young 1, Young 2, and Coyote coal-fired generators, NMPA WAPA allocations, Minnkota's WAPA allocation, and power purchase agreements for wind energy from the Langdon and Ashtabula wind projects to fulfill its energy requirements.

However, since the coal-fired generating units require periodic maintenance during which time they are not generating energy, and since wind is intermittent by nature, the Joint System has to purchase energy to serve its load requirements from the wholesale electric market. During those times when the Joint System doesn't have the generation resources to fulfill its energy requirements, it almost always purchases that energy from the MISO energy market.

A financial danger exists in depending too greatly on the MISO energy market, since the MISO market can be extremely volatile and expensive at times. Also, delivery of market power can be an issue. In order to minimize the financial risk of having to purchase high-cost energy, the Joint System prefers to fulfill as much of its energy requirements as practical from generating resources it owns or has agreements to purchase the output at fixed prices.

7.2 Percentage of Joint System Energy Requirements Purchased from MISO Energy Market

The following tables contain the forecasts of the annual Joint System energy requirements and the amounts of energy purchased from the MISO energy market for the low, median and high load scenarios.

The following table contains the forecasts of the Joint System's annual energy requirements for the low growth, median growth, and the high growth scenarios.

Year	Joint System Low Growth Scenario Energy Requirements MWH	Joint System Median Growth Scenario Energy Requirements MWH	Joint System High Growth Scenario Energy Requirements MWH
2014	4,339,686	4,472,405	4,596,800
2015	4,358,385	4,531,493	4,698,077
2016	4,399,040	4,614,746	4,829,367
2017	4,429,451	4,692,422	4,957,294
2018	4,470,187	4,780,033	5,095,900
2019	4,493,739	4,846,941	5,211,557
2020	4,520,475	4,919,390	5,336,252
2021	4,542,518	4,986,930	5,457,209
2022	4,580,454	5,066,455	5,680,093
2023	4,613,617	5,141,313	5,805,663

2024	4,643,088	5,212,585	5,928,673
2025	4,666,933	5,277,324	6,045,722
2026	4,692,983	5,346,105	6,169,616
2027	4,703,707	5,396,556	6,273,401
2028	4,715,871	5,449,431	6,381,265

The following table contains the forecasts of the Joint System's annual energy purchases from the MISO energy market for the low growth, median growth, and high growth scenarios.

Year	Energy Purchased from MISO Energy Market Low Growth Scenario MWH	Energy Purchased from MISO Energy Market Median Growth Scenario MWH	Energy Purchased from MISO Energy Market High Growth Scenario MWH
2014	179,384	211,730	245,174
2015	100,346	136,107	178,402
2016	134,427	188,026	256,718
2017	77,326	130,725	205,386
2018	96,669	168,699	273,702
2019	67,000	120,408	200,176
2020	31,724	78,246	154,901
2021	34,645	75,583	152,362
2022	32,467	80,937	198,570
2023	12,765	50,338	154,331
2024	9,044	46,205	164,762
2025	25,653	72,881	213,133
2026	25,153	66,703	202,050
2027	30,254	76,969	231,536
2028	29,603	90,962	286,217

From the above tables it can be seen that the forecasted amounts of annual Joint System energy requirements purchased from the MISO energy market are quite small compared to the requirements fulfilled by its own generation and agreements. Given the small amounts of energy that will need to be purchased, the Joint System will be well-shielded from a high-cost and volatile MISO energy market. Therefore, there will be very little risk of financial damage since the Joint System will have minimal dependence on the MISO energy market.

From a comparison of the Joint System's generation resources and the power purchase agreements and the forecasts for peak demand and energy requirements, the Joint System is expected to have adequate capacity and energy resources to meet the great majority of the capacity and energy requirements of its members and will have a very minimal dependence on the MISO energy market. Therefore, there is no need for future generation additions and no need for additional purchase power agreements in the next 15-year time frame.

7.3 Long term resource needs

To meet Minnkota's long term resource needs, Basin Electric, Minnkota and Dairyland are working with other Midwest utilities to explore the potential to participate in a highly efficient advanced class natural gas combined cycle project with a planned COD of

2021, 2022 or 2023 in an effort to diversify its portfolio and meet its capacity and energy requirements. Discussions are underway with a variety of technology providers and developers in an effort to determine what type of project is the most cost-effective for its members.

SECTION 8
Minnesota Renewable Energy Standard

8.1 Discussion

Minnesota Statute 216B.1691 addresses the Renewable Energy Standard, which requires utilities to generate or procure certain amounts of renewable generation.

During the 2007 Legislative session, the statute was amended, in part, to establish a Renewable Energy Standard (RES) with specified mandated renewable energy goals beginning in 2010 and amended the definition of an eligible energy technology.

Each electric utility, other than those that owned a nuclear generating facility as of Jan. 1, 2007, shall 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 at a minimum the following percentages of the electric utility's total electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year as follows:

2010	7%
2012	12%
2016	17%
2020	20%
2025	25%

The definition of an eligible energy technology was changed to one that:

Generates electricity from the following renewable energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen provided that after Jan. 1, 2010, the hydrogen must be generated from resources listed in this clause; or (5) biomass, which includes, without limitation, landfill gas, an anaerobic digester system, and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refused-derived fuel from mixed municipal solid waste as a primary fuel.

Minnkota purchases small amounts of energy from a landfill gas generator located in Fargo, N.D., and from a generator fueled by refuse located in Fosston, Minn. Minnkota also owns two 0.9 MW wind generators, one located near Valley City, ND, and the other located near Petersburg, ND. Since the outputs of these generators are comparatively small relative to Minnkota's large renewable resources, this section will only focus on the large renewable resources. The smaller resources were only noted so that the reader has knowledge of the full extent of the Joint System's renewable energy efforts.

Minnkota has power purchase agreements with NextEra, a wind developer, for portions of its Langdon, N.D., and Ashtabula, N.D., wind projects. From the Langdon wind project, Minnkota has rights to the output of 93 wind turbines with a nameplate capacity of 139.5 MW. From the Ashtabula wind project, Minnkota has rights to the output of 145 wind turbines with a nameplate capacity of 217.5 MW.

Between the Langdon and Ashtabula wind projects, Minnkota has rights to the output of 238 wind turbines with a nameplate capacity of 357 MW. For study purposes it was assumed that the annual capacity factor would be 42 percent, which translates into approximately 1,313,500 MWh of renewable energy for the Joint System.

The following table documents the Joint System's Minnesota RES and North Dakota REO requirements for renewable energy, given its long-term energy forecast and the percent required to be generated by renewable resources. Also displayed in the table are the amounts of renewable energy forecasted to be generated by the portions of the Langdon and Ashtabula wind projects for which Minnkota has power purchase agreements.

Year	Joint System Minnesota Retail Sales MWH	% Required For MN RES	Energy Requirement For MN RES Obligations MWH	Joint System North Dakota Retail Sales MWH	% Required For ND REO	Energy Requirement For ND REO Obligations MWH
2014	1,768,230	12	212,188	2,297,767	0	0
2015	1,778,898	12	213,468	2,340,904	10	234,090
2016	1,795,008	17	305,151	2,400,666	10	240,067
2017	1,813,925	17	308,367	2,452,354	10	245,235
2018	1,835,425	17	312,022	2,510,419	10	251,042
2019	1,851,511	17	314,757	2,555,271	10	255,527
2020	1,868,499	20	373,700	2,604,254	10	260,425
2021	1,890,595	20	378,119	2,643,408	10	264,341
2022	1,918,680	20	383,736	2,687,306	10	268,731
2023	1,940,241	20	388,048	2,733,758	10	273,376
2024	1,962,259	20	392,452	2,776,394	10	277,639
2025	1,983,070	25	495,768	2,814,319	10	281,432
2026	2,001,421	25	500,355	2,858,496	10	285,850
2027	2,014,731	25	503,683	2,891,098	10	289,110
2028	2,026,812	25	506,703	2,927,167	10	292,717

Year	Energy Requirement For MN RES & ND REO Obligations MWH	Langdon & Ashtabula Wind Energy Production MWH	Wind Energy Production Compared to MN RES & ND REO Obligations %
2014	212,188	1,313,500	619%
2015	447,558	1,313,500	293%
2016	545,218	1,313,500	241%
2017	553,602	1,313,500	237%
2018	563,064	1,313,500	233%
2019	570,284	1,313,500	230%
2020	634,125	1,313,500	207%

2021	642,460	1,313,500	204%
2022	652,467	1,313,500	201%
2023	661,424	1,313,500	199%
2024	670,091	1,313,500	196%
2025	777,200	1,313,500	169%
2026	786,205	1,313,500	167%
2027	792,793	1,313,500	166%
2028	799,420	1,313,500	164%

From the above tables it can be seen that the Joint System purchases from renewable energy resources are significantly greater than its requirements. The purchases are 6.19 times the RES & REO requirement in 2014 and are 1.64 times the RES & REO requirement in 2028.

These tables demonstrates the Joint System’s strong dedication to fulfilling its Minnesota RES and North Dakota REO obligations.

SECTION 9
Energy Efficiency and Conservation Program

9.1 Discussion

Energy conservation and efficiency strategies play significant roles for Minnesota cooperatives and municipals in the Joint System's service territories. State law requires Minnesota electric utilities to invest a portion of their revenues each year in conservation improvement programs that promote energy-efficient technologies and practices to their consumers.

In order to meet the state's requirements, the PowerSavers program was designed to help business and residential consumers become more efficient energy users and to also improve Minnkota's own efficiency as an energy provider. The program offers incentives to both residential and business end-use customers.

The residential program includes several incentives for electric heating, ventilation and air conditioning (HVAC), lighting and ENERGYSTAR® appliances.

The business program offers several incentives for HVAC, lighting, motors, adjustable speed drives, refrigeration and compressed air technologies commonly used by businesses.

It is estimated that PowerSavers saved 25,872,370 kWh in 2010, 25,050,178 kWh in 2011, 26,700,330 kWh in 2012, and 27,079,360 kWh in 2013. The Joint System has met the MN energy efficiency and conservation requirements for 2011, 2012, and 2013.

9.2 Development

As part of the Next Generation Energy Act of 2007 (Act), the Minnesota Legislature revised the Conservation Improvement Program (CIP) and renamed it the Energy Efficiency and Conservation (EE&C) Program. The modifications to the Act transitions the program from one that focused on the amount of money spent on conservation to one that focuses on calculated energy savings.

The EE&C Program established an annual energy savings goal of 1.5 percent of annual retail energy sales. The energy savings are based on the average of the prior three-year weather-normalized retail sales.

In the development of the conservation and energy efficiency programs, staff of Minnkota's Minnesota member-owner distribution cooperatives and participating NMPA municipals realized that it would be significantly more beneficial if all the members collaborated as a group to develop ideas and implement consistent energy saving programs for their consumers.

The group organized under the name PowerSavers and includes Beltrami Electric Cooperative, Clearwater-Polk Electric Cooperative, North Star Electric Cooperative, PKM Electric Cooperative, Red River Valley Cooperative Power Association, Red Lake Electric Cooperative, Roseau Electric Cooperative, Wild Rice Electric Cooperative, Bagley Public Utilities, Baudette Municipal Utilities, Fosston Municipal Utilities, Halstad Municipal Utilities, Hawley Public

Utilities, Roseau Municipal Utilities, Stephen Municipal Utilities, Thief River Falls Municipal Utilities and Warren Municipal Utilities.

It was also apparent that help from outside sources was needed to get the various programs off the ground. To that end, Franklin Energy Services (Franklin) of Port Washington, Wis., was chosen to develop a comprehensive set of conservation and efficiency improvement programs to help residential and low income, as well as small and large businesses.

One of the first steps taken by PowerSavers and Franklin was to develop a set of goals for the new endeavor. The five goals were: 1) consistent programs between all the members; 2) effective retail marketing; 3) business ally support; 4) customer behavior modification; and 5) energy efficiency education.

PowerSavers and Franklin developed a program portfolio consisting of five residential and three business programs. The residential programs consist of 1) Prescriptive incentive; 2) Low Income; 3) Direct Installation; 4) Energy Behavior Use Change; and 5) Existing Homes.

The Residential Prescriptive incentive program is designed to provide end-use customers a method of choosing high-efficiency equipment at the time normal equipment is replaced or during major renovations. Recommendations for replacement equipment include heating, ventilation and air conditioning (HVAC) equipment, hot water heaters and Energy Star® clothes washers.

The Residential Low Income program utilizes direct installation services to address domestic hot water and lighting energy use in low income housing. A low income home is defined to be a household with income below 50 percent of state median income. Eligible households are contacted through direct mail and install services.

The Residential Direct Installation program is designed to make an immediate impact on home electric energy usage through the installation of high-efficiency measures. These measures include CFLs, low-flow faucet aerators, showerheads, pre-rinse sprayer valves and water heater temperature turndown. An auditor performs an energy assessment and provides feedback to the homeowner regarding their energy usage.

The Residential Existing Homes program provides homeowners with information, access to qualified contractors and financial incentives to improve energy efficiency for their homes. An auditor conducts a thorough energy assessment as a basis to provide recommendations for efficiency improvements. These assessments often use equipment such as a blower door, which measures the extent of air leaks in the building, and infrared cameras, which reveal heat loss and pinpoint the need for additional insulation.

The Residential Energy Behavior Use Change program is designed to help customers decide how to best address their own energy use behavior. This is done through an online program that allows customers to actuate their own energy usage and monitor how their energy usage increases and/or decreases based on behavior changes they make in their homes. Turning off lights, turning down water heaters and using a programmable thermostat are just a few examples.

The business programs are 1) Prescriptive incentive; 2) Custom; and 3) Direct Installation.

The Business Prescriptive incentive program provides financial incentives and information to increase the use of high-efficiency HVAC technologies, lighting, motors and drives, variable speed drives and food service equipment commonly utilized by businesses.

The Business Custom program aids retail, agricultural, school, commercial and industrial customers in installing a variety of energy-saving technologies not included in the Business Prescriptive incentive program.

The Business Direct Installation program is designed to make an immediate impact on commercial electric energy usage through the installation of high-efficiency measures. These measures include CFLs, low-flow faucet aerators, showerheads, pre-rinse sprayer valves, water heater temperature turndown and LED exit light retrofits.

SECTION 10
Region Transmission Owner (RTO) Participation

10.1 Discussion

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

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.

At this time, Minnkota does not believe that joining an RTO such as MISO will be cost-effective. However, Minnkota will continue to evaluate membership in MISO.

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 345 kV, 230 kV, 115 kV, and 69 kV transmission facilities required to maintain reliable and economical service to its member systems' 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 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 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 entities such as the Mid-Continent Area Power Pool (MAPP), MISO, Minnesota Transmission Owners (MTO), and CapX2020.

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 115 kV and above for the ensuing 10 years. This plan integrates the transmission plans developed by individual MAPP members as well as plans developed by MAPP subcommittees. As a MAPP member that owns and operates transmission facilities, Minnkota is required to participate in the MAPP planning processes.

The objectives of the regional planning process are to avoid 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 its 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. 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 a member of the MTO.

The MTO has responsibility for the Minnesota Biennial Transmission Projects Report. The major purpose 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 standard.

11.2.4 CAPX2020

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 CapX2020 refers to Capital Expenditures by the year 2020.

The mission of the CapX2020 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 the public interest.

Although not a member of CapX2020, Minnkota has been active in many of the working groups and the planning efforts to date and will continue participation in future planning studies.

SECTION 12
Environmental Information

12.1 General

Minnkota operates the Milton R. Young (MRYS) near Center, North Dakota. Unit 1 of the station is owned by Minnkota and has a rating of 250 MW. Unit 2, which is owned by Square Butte Electric Cooperative (affiliated with Minnkota by common ownership), has a rating of 455 MW. Unit 1 went online in 1970, while Unit 2 began operations in 1977. Both units are fired on lignite obtained from BNI Coal Ltd's (Allete) Center Mine, which is adjacent to the MRYS. Within the last few years, Minnkota has completed construction of $425 million in environmental upgrades at the MRYS.

12.2 Regional Haze

A 2006 Consent Decree (CD) among Minnkota/Square Butte Cooperative, the United States, on behalf of the EPA, and the State of North Dakota (State) set out the requirements for the MRYS to limit NOx, SO2, and PM. The underlying case venued in United States District Court for the District of North Dakota was captioned *United States of America, State of North Dakota v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative* (Civil Action No. 1:06-CV-034) and alleged violations of the New Source Review (NSR) provisions of the Clean Air Act relating to construction activities commenced without first applying for a Prevention of Significant Deterioration (PSD) permit.

Pursuant to the CD, the parties agreed the limitation for NOx would be determined by a BACT analysis, for which the State of North Dakota would make the final determination. Ultimately, the State of North Dakota found that Selective Non-Catalytic Reduction (SNCR) and Over-Fire Air (OFA) were BACT for NOx. Minnkota subsequently installed SNCRs and OFAs, along with an SO2 scrubber on Unit 1, at a cost of over $420 million, which reduces NOx by 55 to 60 percent and reduces SO2 for Unit 1 by 95 percent and Unit 2 by 90 percent. EPA disagreed with the State of North Dakota's findings on NOx that SNCR was BACT. As a result, the EPA initiated the dispute resolution process as outlined in the CD.

In 2010, the State of North Dakota submitted to the EPA for approval a state implementation plan (SIP) under the Clear Air Act's Regional Haze program. As a facility built between 1962 and 1977 that has the potential to emit matter that could impact visibility, MRYS was subject to Best Available Retrofit Technology (BART). Under that program, the State found that for SO2, 95 percent removal was required. For NOx, SNCR plus OFA was found to be BART for Minnkota's MYRS. In February of 2011, the EPA proposed to approve and disapprove portions of the ND SIP. Additionally, the EPA expressed its intent to promulgate a federal implementation plan (FIP) for NOx emissions.

In July 2011, the EPA issued a proposed FIP that would have required MRYS to install Selective Catalytic Reduction (SCR) technology. SCRs are much more expensive than OFA+SNCR technology and have not proven to work on cyclone-fired boilers using North Dakota lignite coal.

On March 2, 2012, the EPA approved North Dakota's (SIP) regarding nitrogen oxides (NOx) emissions for Units 1 and 2 at Minnkota's MRYS. A December 2011 court ruling weighed heavily in the EPA's decision to approve the SIP for MYRS. As the EPA explained, "[a]fter considering a recent judicial decision, we have decided to approve North Dakota's NOx BART determinations for [Milton R. Young Station] 1 and 2 . . . and to not promulgate a FIP for NOx BART for these units." 77 Fed. Reg. 20894, 20897 (Apr. 6, 2012). In that case, a U.S. District Court ruled in favor of the state of North Dakota in a dispute resolution process under the Consent Decree for what is Best Available Control Technology (BACT) for NOx at the Young Station.

The Court denied the EPA's motion to stay the CD dispute resolution process until the regional haze process was completed. The Court ruled that the state's finding that BACT for NOx at the Young Station was SNCR – and not SCR – was not unreasonable nor was it arbitrary and capricious.

The National Parks Conservation Association and the Sierra Club subsequently petitioned the EPA to administratively reconsider their final rule partially approving North Dakota's Regional Haze SIP. On March 15, 2013, EPA initiated reconsideration of its approval of North Dakota's BART emission limits for NOx for MRYS and Leland Olds Station Unit 2. EPA held a hearing for public comment on the reconsideration of their Regional Haze determination on May 15, 2013. EPA is expected to make a final ruling in the 2014.

In a parallel process, the National Parks Conservation Association and the Sierra Club petitioned the 8th Circuit Court of Appeals for review of the EPA's partial approval of the North Dakota Regional Haze SIP. The Court of Appeals held its hearing on this matter and ruled in September of 2013 that because the environmental groups' challenges to the state's BART determination for the Young Station Units 1 and 2 were not raised before EPA during the final rulemaking process, the 8th Circuit was without jurisdiction to hear them.

12.3 MACT

The EPA's Maximum Achievable Control Technology (MACT) rule requires coal and oil-fired power plants to reduce emissions of mercury, other metallic air toxics, acid gases, and organic air toxics. EPA's March 16, 2011 Utility MACT rule complies with a Consent Decree of the D.C. Court of Appeals that requires EPA to fulfill the 1990 Clean Air Act regarding hazardous air pollution from power plants. The Clean Air Act required EPA to determine whether such regulation is "appropriate and necessary," which EPA did in 2000.

Following the Clean Air Act's approach for toxic pollutants, the rule requires "command and control" emission rate limits for mercury, acid gases, and particles. The limits must represent Maximum Achievable Control Technology, defined as the top 12% performance of existing units, which EPA set after collecting performance data from industry. In addition, the proposal establishes "work practice standards" to reduce organic air toxics, such as dioxin and furans.

One particular difficulty Minnkota faces in meeting the MACT standards is with regard to mercury. Mercury takes several different forms, from elemental mercury to oxidized forms. North Dakota lignite predominately contains elemental mercury, which is particularly difficult to remove. To meet that challenge, Minnkota is continuing to explore and pursue technology to meet the MACT mercury emission standard of 4 lb/Tbtu (an approximate 55-60% reduction), and is optimistic about the ability to achieve that standard.

12.4 Proposed Carbon Rules

Minnkota continues to be concerned with EPA's regulations for carbon for both new and existing sources. EPA published proposed greenhouse gas emission limits for new coal-fired power plants in early January 2014 and is expected to propose corresponding emissions guidelines for existing power plants by no later than June 2014. Both proposals are likely to encounter strong opposition and will almost certainly result in litigation once they are finalized.

The principle legal dispute with respect to new power plants is whether EPA's proposed emission limits for coal plants (which are based on the partial use of carbon capture and sequestration technologies) are based on an emission reduction system that has been "adequately demonstrated" within the meaning of the Clear Air Act Section 111. The legal issues with respect to existing power plants are more complicated, but legal challenges are expected as to whether EPA has the authority to use Section 111(d) in the first place. Further, assuming EPA has that authority, the question becomes whether the 111(d) emission guidelines are to be based on "inside the fence" emission reduction measures (such as retrofits), or on "outside the fence" measures such as state-level energy efficiency programs.

SECTION 13
Two-Year Action Plan

The Joint System will take the following actions during the 2015 and 2016 time frames as part of its ongoing efforts in Integrated Resource Planning:

A Load Forecast Study (LFS) will be completed for each of the 11 member systems and Minnkota in 2015. The LFS will track the growth in the demand and energy requirements of the members.

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.

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.

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.

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 2017, 2018, and 2019 time frames as part of its ongoing efforts in Integrated Resource Planning:

A Load Forecast Study (LFS) will be completed for each of the 11 member systems and Minnkota in 2017 and 2019. These studies will track the growth in the demand and energy requirements of the member systems. The LFS forecasts will be an important and ongoing part of the Integrated Resource Planning process.

Minnkota staff will continue to analyze and forward recommendations to the Minnkota Board of Directors on the best methods of promoting and enhancing Demand Response activities.

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.

Future Integrated Resource Plans will be completed as required.

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 MISO 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 other than costly standby diesel generators. 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 Minnkota's lignite-fired generators was shut down for a limited period of time (less than a year), Minnkota would likely purchase replacement power from MISO market and neighboring utilities until the unit was returned to service. The cost of the replacement energy would be dictated by the market conditions at the time of the outage and the length of time replacement energy had to be secured.

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 and capacity. It is difficult to estimate the likelihood of successfully purchasing replacement power and capacity for the length of time needed to install new generation capacity. However, it would take two to three years to install new 5 simple cycle gas-fired generation and three to five years to install a new combined cycle combustion turbine. Given the Current regulatory climate it is unlikely new coal-fired generation could be constructed.

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.

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 (SO2), nitrous oxide (NOX), 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 plans for adding generation capacity. In the future, when additional generation is needed, Minnkota will complete an analysis of its capacity options considering the MN PUC's adopted environmental externality values.

SECTION 17
Renewable Resource Scenarios – 50% and 75%

The Joint System is not planning to add any new generation capacity in the 2014-2028 timeframe. If the Joint System is required to utilize renewable generation for either a 50% or 75%t share of any new generation addition, the most likely renewable resource would be wind.

However, because 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% or 75% renewable resources will be significantly more costly than the base case option because of the low availability of wind resources and the fact that backup generation such as a gas turbine will be needed to serve firm load when the wind resources are not producing any energy.

The Joint System does not believe that the 50% and 75% 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 30, 2014	Bemidji, MN
Cass County Electric Cooperative	April 28, 2014	Kindred, ND
Cavalier Rural Electric Cooperative	April 23, 2014	Langdon, ND
Clearwater-Polk Electric Cooperative	April 30, 2014	Bagley, MN
Nodak Electric Cooperative	June 3, 2014	Grand Forks, ND
North Star Electric Cooperative	April 3, 2014	Grand Forks, ND
PKM Electric Cooperative	April 27, 2014	Warren, MN
Red Lake Electric Cooperative	April 30, 2014	Red Lake Falls, MN
Red River Valley Cooperative Power Assoc.	April 21, 2014	Halstad, MN
Roseau Electric Cooperative	May 28, 2014	Roseau, MN
Wild Rice Electric Cooperative	April 29, 2014	Mahnomen, MN
Northern Municipal Power Agency	May 21, 2014	Thief River Falls, MN
Minnkota Power Cooperative, Inc.	June19, 2014	Grand Forks, ND

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

SECTION 19
Plan is in the Public Interest

19.1 Maintain or Improve the Adequacy of Utility Service

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

19.3 Minimize Adverse Socioeconomic 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 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 Demand Response program, has numerous transmission ties with various area utilities, is a MISO market participant, and has 357 MW of wind capacity through power purchase agreements. 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 IRP outlines the concerns about these risks and discusses how the risks may be avoided or minimized.

19.6 Summary

The IRP fulfills the requirements of 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 Statue		Reference Section
216B.1691 *Subdivision 2*	Report on plans, activities, and progress with regard to the renewable energy objectives.	8
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	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 nontechnical summary not to exceed 25 pages in length.	2
Notice	Submit an original copy of the filing as an unbound, one-sided document on 8½-by-11 paper with no tabbed dividers.	Enclosed with PUC Filing

20.2 Cross Reference to 2010 Integrated Resource Plan Two-Year Action Plan

Section

A.	A Load Forecast Study (LFS) will be completed for each of the 11 member systems and Minnkota in 2011. The LFS will track the growth in the demand and energy requirements of the member systems.	**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.	**Completed**
C.	Minnkota staff will continue to study and forward recommendations to the Minnkota Board of Directors concerning modifications or additions needed to 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.	Upgrade of the sulfur dioxide (SO2) scrubber to effect 90% removal efficiency on Young 2 in 2010.	**Completed**
F.	Installation of a wet SO2 scrubber with a removal efficiency of 95% on Young 1 by the end of 2011.	**Completed**
G.	Installation of additional nitrous oxides (NOx) controls on Young 2 by the end of 2010.	**Completed**
H.	Installation of additional NOx controls on Young 1 by the end of 2011.	**Completed**

20.3 Cross Reference to 2010 Integrated Resource Five-Year Action Plan

Section

A.	A Load Forecast Study (LFS) will be completed for each of the 11 member systems and Minnkota in 2013 and 2015. These studies will track the growth in the demand and energy requirements of the member systems. The LFS forecasts will be an important and ongoing part of the Integrated Resource Planning process.	**Ongoing**
B.	Minnkota staff will continue to analyze and forward recommendations to the Minnkota Board of Directors on the best methods of promoting and enhancing Demand Response 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**

APPENDIX A

Minnesota Electric Utility Annual Report

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0120 REGISTRATION

ENTITY ID#	69
REPORT YEAR	2013

Number of Power Plants	6

UTILITY DETAILS

UTILITY NAME	Minnkota Power Coop
STREET ADDRESS	1822 Mill Road
CITY	Grand Forks
STATE	ND
ZIP CODE	58203
TELEPHONE	701/795-4315

Scroll down to see allowable UTILITY TYPES

* UTILITY TYPE	Co-op

CONTACT INFORMATION

CONTACT NAME	JAMIE OVERGAARD
CONTACT TITLE	RATES, LOAD AND PLANNIBG MANAGER
CONTACT STREET ADDRESS	1822 MILL ROAD
CITY	GRAND FORKS
STATE	ND
ZIP CODE	58203
TELEPHONE	701-795-4219
CONTACT E-MAIL	jovergaard@minnkota.com

UTILITY OFFICERS

NAME	TITLE
COLLIN JENSEN	CHAIRMAN
RUSSELL OKESON	VICE CHAIRMAN
JEFFERY FOLLAND	SECRETARY-TREASURER
ROBERT MCLENNAN	PRESIDENT & CEO

PREPARER INFORMATION

PERSON PREPARING FORMS	JAMIE OVERGAARD
PREPARER'S TITLE	RATES, LOAD AND PLANNIBG MANAGER
DATE	6/12/2014

COMMENTS

ALLOWABLE UTILITY TYPES

Code

Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION

FEDERAL AGENCY	FORM NUMBER	FORM TITLE	FILING CYCLE (enter an "X" in the cell) MONTHLY	YEARLY	OTHER

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

A utility shall provide the following information for the last calendar year:

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

If applicable, the Largest Customer List must be submitted either in electronic or paper format. If information is Trade Secret, note it as such.

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

The referenced map must be submitted either in electronic or paper format.

See Instructions for details of the information required on the Minnesota Service Area Map.

D. PURCHASES AND SALES FOR RESALE

UTILITY NAME	INTERCONNECTED UTILITY	MWH PURCHASED	RESALE ONLY MWH SOLD FOR RESALE
MANITOBA HYDRO		7,708	0
XCEL		0	387,925
WESTERN AREA POWER ADMINISTRATION		534,213	0
MISO		336,743	1,062,404
MISC		326,900	37,800

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

A utility shall provide the following information for the last calendar year:

E. RATE SCHEDULES	**The rate schedule and monthly power cost adjustment information must be submitted in electronic or paper format.**

See Instructions for details of the information required on the Rate Schedules and Monthly Power Cost Adjustments.

F. REPORT FORM EIA-861	**A copy of report form EIA-861 filed with the US Dept. of Energy must be submitted in electronic or paper format.**

A copy of the report form EIA-861 filed with the Energy Information Administration of the US Dept. of Energy must be submitted.

G. FINANCIAL AND STATISTICAL REPORT	**If applicable, a copy of the Financial and Statistical Report filed with the US Dept. of Agriculture must be submitted in electronic or paper format.**

For rural electric cooperatives, a copy of the Financial and Statistical Report to the US Dept of Agriculture must be submitted.

H. GENERATION DATA

If the utility has Minnesota power plants, enter the fuel requirements and generation data on the Plant1, Plant2, etc. worksheets.

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

See Instructions for details of the information required for residential space heating users.

COL. 1 NO. OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COL. 2 NO. OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COL. 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
39,240	39,240	1,225,680

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY COUNTY FOR THE LAST CALENDAR YEAR

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin		46	Martin	
2	Anoka		47	Meeker	
3	Becker		48	Mille Lacs	
4	Beltrami		49	Morrison	
5	Benton		50	Mower	
6	Big Stone		51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton		54	Norman	
10	Carver		55	Olmstead	
11	Cass		56	Otter Tail	
12	Chippewa		57	Pennington	
13	Chisago		58	Pine	
14	Clay		59	Pipestone	
15	Clearwater		60	Polk	
16	Cook		61	Pope	
17	Cottonwood		62	Ramsey	
18	Crow Wing		63	Red Lake	
19	Dakota		64	Redwood	
20	Dodge		65	Renville	
21	Douglas		66	Rice	
22	Faribault		67	Rock	
23	Fillmore		68	Roseau	
24	Freeborn		69	St. Louis	
25	Goodhue		70	Scott	
26	Grant		71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	
29	Hubbard		74	Steele	
30	Isanti		75	Stevens	
31	Itasca		76	Swift	
32	Jackson		77	Todd	
33	Kanabec		78	Traverse	
34	Kandiyohi		79	Wabasha	
35	Kittson		80	Wadena	
36	Koochiching		81	Waseca	
37	Lac Qui Parle		82	Washington	
38	Lake		83	Watonwan	
39	Lake of the Woods		84	Wilkin	
40	Le Sueur		85	Winona	
41	Lincoln		86	Wright	
42	Lyon		87	Yellow Medicine	
43	McLeod				
44	Mahnomen			GRAND TOTAL (Entered)	
45	Marshall				
				GRAND TOTAL (Calculated)	0

<= (Should equal "Megawatt-hours" column total on ElectricityByClass worksheet)

COMMENTS

DATA IS NOT AVAILABLE.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY MONTH FOR THE LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Past Year Entire System		A Non-Farm Residential	B Residential With Space Heat	C Farm	D Small Commercial & Industrial	E Irrigation	F Large Commercial & Industrial	G Street & Highway Lighting	H Other (Include Municipals)	I Total (Columns A through H)
January	No. of Customers	46,909		78,228	10,772	0	422	617	118	137,066
	MWH	93,417		177,705	89,438	0	64,868	1,031	17,787	444,246
February	No. of Customers	46,874		78,260	10,785	0	423	617	118	137,077
	MWH	93,110		178,682	90,504	0	64,646	939	16,780	444,662
March	No. of Customers	46,910		78,364	10,781	0	423	618	118	137,214
	MWH	75,863		143,698	78,656	0	53,820	785	15,218	368,040
April	No. of Customers	46,951		78,466	10,797	0	429	618	118	137,379
	MWH	70,039		138,296	77,583	0	61,473	756	15,165	363,312
May	No. of Customers	47,220		79,036	10,814	0	429	618	118	138,235
	MWH	48,449		91,818	70,813	0	60,554	619	12,503	284,756
June	No. of Customers	47,078		78,728	10,838	0	431	619	118	137,812
	MWH	40,624		73,645	69,356	0	55,343	600	14,309	253,878
July	No. of Customers	47,098		78,893	10,866	0	430	619	118	138,024
	MWH	46,136		84,329	74,306	0	50,013	591	14,182	269,557
August	No. of Customers	47,234		79,044	10,812	0	429	620	118	138,257
	MWH	42,820		77,475	74,561	0	57,271	662	14,128	266,918
September	No. of Customers	47,305		79,256	10,901	0	432	620	118	138,632
	MWH	47,007		88,770	78,685	0	62,290	784	14,617	292,154
October	No. of Customers	47,369		79,504	10,962	0	434	619	118	139,006
	MWH	45,046		82,997	75,231	0	62,856	882	14,473	281,485
November	No. of Customers	47,497		79,827	10,981	0	436	622	119	139,482
	MWH	71,612		146,517	97,387	0	68,847	997	15,268	400,627
December	No. of Customers	47,534		79,916	10,991	0	435	623	119	139,618
	MWH	99,358		194,204	147,347	0	83,465	1,092	25,367	550,833
	Total MWH	773,481	0	1,478,137	1,023,868	0	745,448	9,738	189,796	4,220,468

Comments	
	MINNKOTA IS NOT ABLE TO FUTHER CLASSIFY RESIDENTIAL SALES AS TO WHICH INCLUDE SPACE HEATING REQUIREMENTS AND WHICH DO NOT INCLUDE SPACE HEATING REQUIREMENTS.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

ELECTRICITY DELIVERED TO ULTIMATE CONSUMERS IN MINNESOTA SERVICE AREA IN LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Exclude station use, distribution losses, and unaccounted for energy losses from this table altogether.

Classification of Energy Delivered to Ultimate Consumers (include energy used during the year for irrigation and drainage pumping)	In this column report the number of farms, residences, commercial establishments, etc., and not the number of meters, where different. Number of Customers at End of Year	This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county. Megawatt-hours (round to nearest MWH)	This column total will be used for the Alternative Energy Assessment and should not include revenues from sales for resale (MN Statutes Sec. 216B.62, Subd. 5). Revenue ($)
Farm	41,480	754,787	84,436,819
Nonfarm-residential	28,732	438,927	49,030,273
Commercial	6,165	478,915	42,149,379
Industrial	357	141,121	11,232,684
Street and highway lighting	166	1,385	209,003
All other	71	86,268	5,660,879
Entered Total	76,971	1,901,403	192,719,036
CALCULATED TOTAL	76,971	1,901,403	192,719,036

Comments

Non-farm ($/kWh)	Residential ($/customer)
0.111705	1706.465
CHECK	CHECK

	REMEMBER TO SEND THE FOLLOWING ATTACHMENTS:
1	If applicable, the Largest Customer List (Attachment ELEC-1), if the separate LargestCustomers spreadsheet file was not used (pursuant to MN Rules Chapter 7610.0600 B.)
2	Minnesota service area map (pursuant to MN Rules Chapter 7610.0600 C.)
3	Rate schedules and monthly power cost adjustments (pursuant to MN Rules Chapter 7610.0600 E.)
4	Report form EIA-861 filed with US Dept. of Energy (pursuant to MN Rules Chapter 7610.0600 F.)
5	If applicable, for rural electric cooperatives, the Financial and Statistical Report filed with US Dept. of Agriculture (pursuant to MN Rules Chapter 7610.0600 G.)

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Milton R. Young Station	PLANT ID	69012
STREET ADDRESS	3401 24th Street SW		
CITY	Center		
STATE	ND	NUMBER OF UNITS	2
ZIP CODE	58530		
COUNTY	Oliver		
CONTACT PERSON	LOWELL STAVE		
TELEPHONE	701-795-4212		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1970	LIG	1,699,451	
2	USE	ST	1977	LIG	2,509,244	TOTAL GENERATION
					1,255,436	MPC SHARE
				Plant Total	5,464,131	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	250.0	250.0	76.97	85.7	1.9	
2	448.0	455.0	62.17	70.1	8.3	
	224.0	227.5				
	MPC SHARE	MPC SHARE				
Plant Total	922.0	932.5				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	LIG	1,465,413	TONS	6,760	FO2	486,119	GALLONS	
2	LIG	2,102,746	TONS	6,670	FO2	431,299	GALLONS	
		1,052,055	TONS			215,789	GALLONS	
		MPC SHARE				MPC SHARE		

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage)

100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Coyote Steam (30% share)	PLANT ID	69002
STREET ADDRESS	PO Box 339		
CITY	Beulah		
STATE	ND	NUMBER OF UNITS	1
ZIP CODE	58523		
COUNTY	Mercer		
CONTACT PERSON	LOWELL STAVE		
TELEPHONE	701-795-4212		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1981	LIG	2,641,260	TOTAL NET GENERATION
					811,475	MPC SHARE
				Plant Total	3,452,735	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	427.0	427.0	70.60	80.6	15.1	
	128.1	128.1				
	NMPA SHARE	NMPA SHARE				
Plant Total	555.1	555.1				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	LIG	2,105,090	TONS	6,988	FO2	559,690	GALLONS	
		646,747	TONS			171,954	GALLONS	
		NMPA SHARE				NMPA SHARE		

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage)

100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Infinity Wind Valley City	PLANT ID	69014
STREET ADDRESS	1822 Mill Road		
CITY	Grand Froks		
STATE	ND	NUMBER OF UNITS	1
ZIP CODE	58203		
COUNTY	Grand Forks		
CONTACT PERSON	LOWELL STAVE		
TELEPHONE	701-795-4212		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	WI	2002	WIND	2,700	
				Plant Total	2,700	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.9	0.9	34.20	98.4		
Plant Total	0.9	0.9				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source &	BIT	Bituminous Coal		WI	Wind
Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage)

100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Infinity Wind Petersburg	PLANT ID	69015
STREET ADDRESS	PO Box 13200		
CITY	Grand Forks		
STATE	ND	NUMBER OF UNITS	1
ZIP CODE	58203		
COUNTY	Grand Forks		
CONTACT PERSON	LOWELL STAVE		
TELEPHONE	701-795-4212		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	WI	2002	Wind	2,370	
				Plant Total	2,370	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.9	0.9	30.10	96.7		
Plant Total	0.9	0.9				

D. UNIT FUEL USED

PRIMARY FUEL USE					SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source & Fuel Type**	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage)

100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

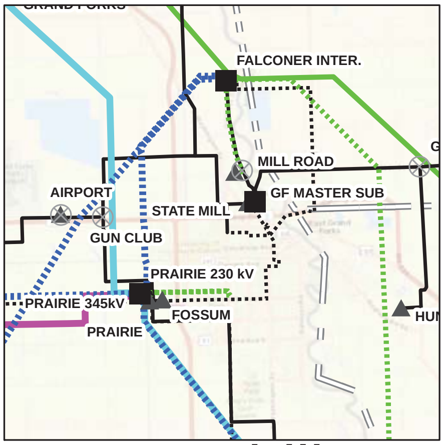
Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

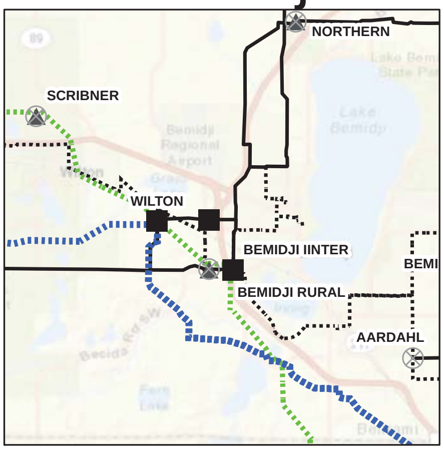
APPENDIX B

Minnesota Service Area Maps

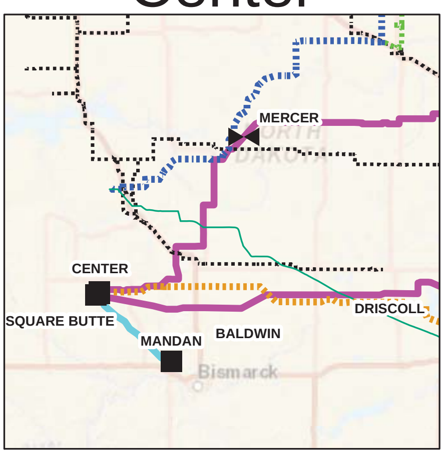
Grand Forks



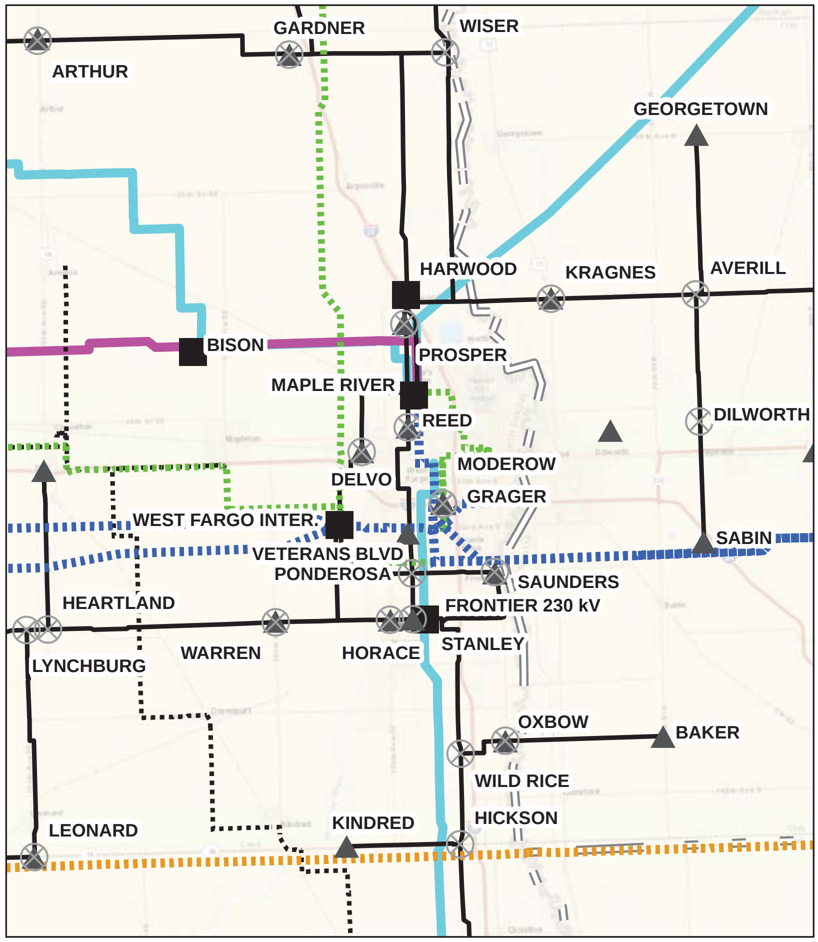
Bemidji



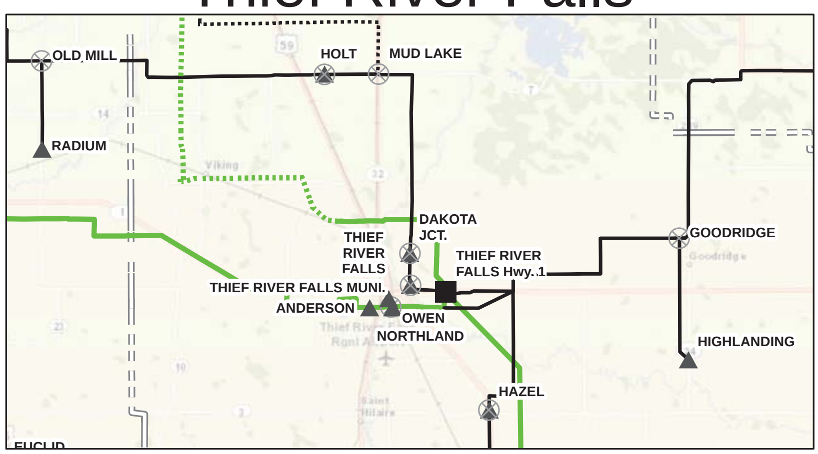
Center

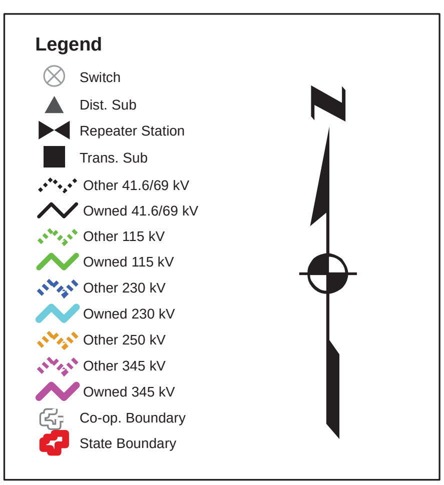


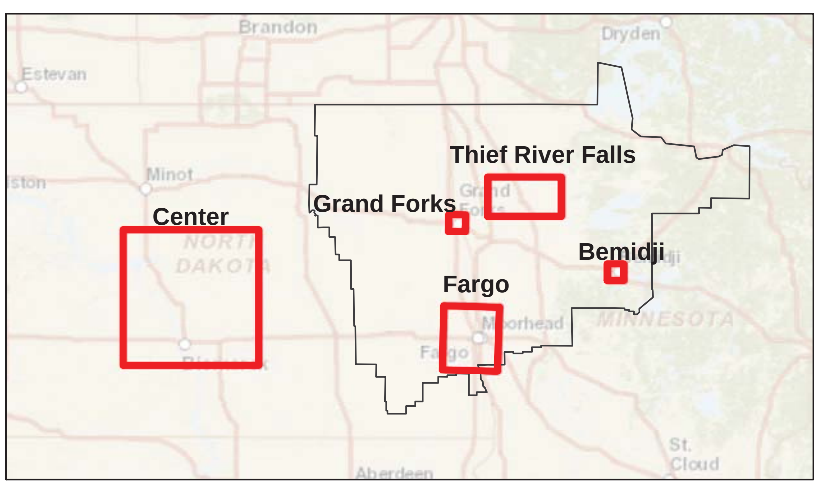
Fargo



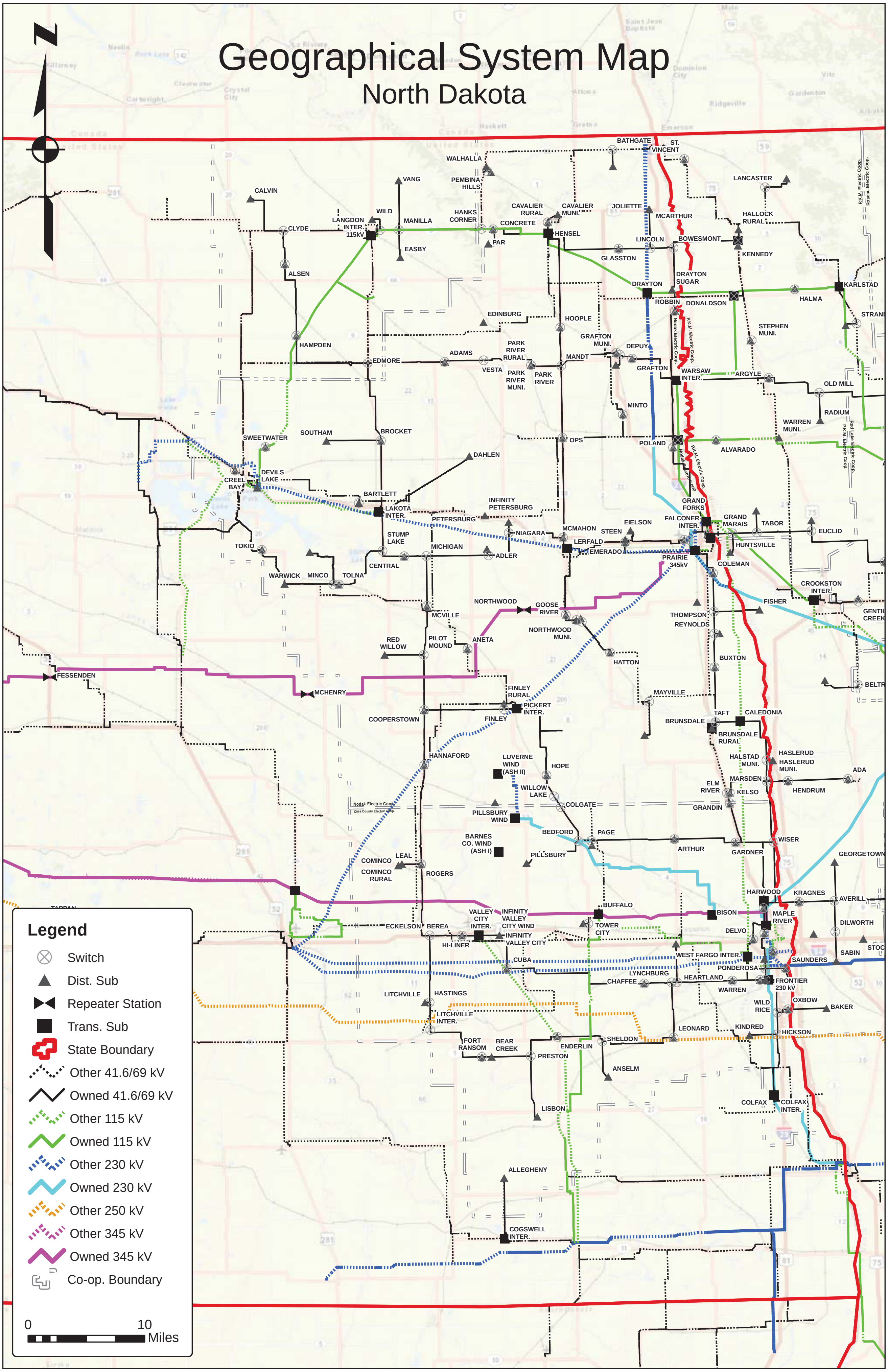
Thief River Falls







Geographical System Map
Minnesota
N
Legend
Switch
Dist. Sub
Repeater Station
Trans. Sub
State Boundary
Other 41.6/69 kV
Owned 41.6/69 kV
Other 115 kV
Owned 115 kV
Other 230 kV
Owned 230 kV
Other 250 kV
Other 345 kV
Owned 345 kV
Co-op. Boundary
0
20
Miles


Geographical System Map
North Dakota
Legend
Switch
Dist. Sub
Repeater Station
Trans. Sub
State Boundary
Other 41.6/69 kV
Owned 41.6/69 kV
Other 115 kV
Owned 115 kV
Other 230 kV
Owned 230 kV
Other 250 kV
Other 345 kV
Owned 345 kV
Co-op. Boundary
0
10
Miles
BATHGATE
ST. VINCENT
WALHALLA
LANCASTER
VANG
PEMBINA HILLS
CALVIN
CAVALIER RURAL
CAVALIER MUNI.
JOLIETTE
HALLOCK RURAL
MCARTHUR
WILD
HANKS CORNER
LANGDON INTER. 115kV
MANILLA
CONCRETE
CLYDE
HENSEL
LINCOLN
BOWESMONT
PAR
EASBY
KENNEDY
GLASSTON
ALSEN
DRAYTON SUGAR
DRAYTON
KARLSTAD
ROBBIN
DONALDSON
HALMA
EDINBURG
HOOPLE
STEPHEN MUNI.
GRAFTON MUNI.
HAMPDEN
PARK RIVER RURAL
DEPUY
ADAMS
MANDT
EDMORE
VESTA
GRAFTON
WARSAW INTER.
ARGYLE
PARK RIVER MUNI.
PARK RIVER
OLD MILL
MINTO
RADIUM
WARREN MUNI.
SWEETWATER
SOUTHAM
BROCKET
OPS
POLAND
ALVARADO
DAHLEN
DEVILS LAKE
CREEL BAY
BARTLETT
INFINITY PETERSBURG
GRAND FORKS
LAKOTA INTER.
PETERSBURG
EIELSON
FALCONER INTER.
GRAND MARAIS
TABOR
EUCLID
MCMAHON
STEEN
STUMP LAKE
NIAGARA
LERFALD
HUNTSVILLE
MICHIGAN
TOKIO
EMERADO
PRAIRIE 345kV
ADLER
CENTRAL
COLEMAN
WARWICK
MINCO
TOLNA
CROOKSTON INTER.
NORTHWOOD
GOOSE RIVER
FISHER
MCVILLE
THOMPSON
REYNOLDS
NORTHWOOD MUNI.
RED WILLOW
PILOT MOUND
ANETA
HATTON
BUXTON
FESSENDEN
MCHENRY
FINLEY RURAL
MAYVILLE
PICKERT INTER.
COOPERSTOWN
FINLEY
TAFT
CALEDONIA
BRUNSDALE
BRUNSDALE RURAL
HANNAFORD
LUVERNE WIND (ASH II)
HOPE
HALSTAD MUNI.
HASLERUD
HASLERUD MUNI.
MARSDEN
ADA
ELM RIVER
KELSO
HENDRUM
WILLOW LAKE
COLGATE
GRANDIN
PILLSBURY WIND
BEDFORD
PAGE
BARNES CO. WIND (ASH I)
ARTHUR
WISER
GARDNER
PILLSBURY
GEORGETOWN
COMINCO
LEAL
COMINCO RURAL
ROGERS
HARWOOD
KRAGNES
AVERILL
BUFFALO
BISON
MAPLE RIVER
VALLEY CITY INTER.
INFINITY VALLEY CITY WIND
ECKELSON
BEREA
TOWER CITY
DELVO
DILWORTH
INFINITY VALLEY CITY
HI-LINER
WEST FARGO INTER.
SABIN
CUBA
SAUNDERS
PONDEROSA
LYNCHBURG
CHAFFEE
HEARTLAND
FRONTIER 230 kV
WARREN
LITCHVILLE
HASTINGS
OXBOW
WILD RICE
BAKER
LITCHVILLE INTER.
LEONARD
KINDRED
HICKSON
SHELDON
FORT RANSOM
BEAR CREEK
ENDERLIN
PRESTON
ANSELM
COLFAX
COLFAX INTER.
LISBON
ALLEGHENY
COGSWELL INTER.
P.K.M. Electric Coop.
Roseau Electric Coop.
Nodak Electric Coop.
Red Lake Electric Coop.
Cass County Electric Coop.

APPENDIX C

Minnkota Power Cooperative Inc

Wholesale Power Rate

MINNKOTA POWER COOPERATIVE, INC.

2014-2015

Minnkota Wholesale Power Rate

April 1, 2014 to April 1, 2015

MINNKOTA POWER COOPERATIVE, INC.
GRAND FORKS, NORTH DAKOTA

WHOLESALE POWER RATE FOR CLASS A MEMBERS
FOR THE PERIOD
APRIL 1, 2014 TO APRIL 1, 2015
SUBJECT TO THE APPROVAL OF THE
RURAL UTILITIES SERVICE

I. Firm Power and/or Interruptible Energy Services

A. Rate Schedule:

1. Energy Charge: $0.03353 (33.53 mills) per kWh

1A. Energy Surcharge: $0.004 (4 mills) per kWh

2. Demand Charge:
   a. Winter
   $78.12 per kW per year ($6.51/kW/month) of winter billing demand, plus

   b. Summer
   $78.12 per kW per year ($6.51/kW/month) of summer billing demand

3. Transmission Charge:
   a. Demand
   $42.12 per kW per year ($3.51/kW/month) of transmission demand, plus

   b. Energy
   $0.00436 (4.36 mills) per kWh on: 1) all energy metered at the substation delivery points, and 2) all energy produced by a synchronously connected generator larger than 500 kW that operates for more than 1,000 hours per year nominally which is owned by the Class A member or their customers. Minnkota reserves the right to require special metering and assess a

transmission charge on loads that otherwise would not pay an adequate transmission charge.

4. Substation Charge:

a. Fixed
$15,360 per substation per year ($1,280/sub/month), plus

b. Variable
$7.32 per kW per year ($0.61 /kW/month) of the highest kW demand registered at each substation during 2013

The Energy Charge, Energy Surcharge and Transmission Energy Charges are billed monthly based on actual usage. The Demand Charge, Transmission Demand Charge and Substation Charge are payable in twelve equal monthly payments.

B. Determination of Billing Demand:

1. Metered Demand Adjustments

a. WAPA Customers Adjustment. The following loads receive fixed WAPA power deliveries and will have 85% of their winter and summer Contract Rate of Delivery (CROD), adjusted for losses, credited toward their hourly coincident metered demands with each hour's resultant metered demand to be not less than zero:

	Winter Credit kW	Summer Credit kW	Supplying System
Hope Municipal	479	329	Nodak
Sharon Municipal	240	118	Nodak
ND Mill	3,256	3,188	Nodak

b. Qualified Cogenerator Standby Service Adjustment. The winter and summer coincident metered demand associated with each Qualified Facility of each Class A Member will be reduced by an amount equal to the difference between the amount of standby capacity purchased and the output of the cogenerator calculated on an hourly basis, with each hour's resultant metered demand to be not less than zero.

c. Power Factor Adjustment. Class A Members shall at all times take and use power in such a manner that the power factor shall be as near 100 percent as practical. At the option of Minnkota when the power factor at any delivery point during any hour is less than 95 percent leading or lagging, the metered demands for said delivery point used for billing purposes shall be increased by the ratio:

$$\frac{.95}{\text{The lowest hourly power factor (lead or lag) recorded in the current billing month.}}$$

d. Vickaryous Substation Adjustment. It has been agreed by Minnkota and Roseau Electric Cooperative to not operate demand response/load management during winter billing peaks at Vickaryous. Consequently, the winter metered demands at Vickaryous will be reduced by 33% to represent past winter demand response/load management activity that will no longer be exercised during billing peaks.

2. Winter Method. After adjustment of winter metered demands in accordance with Section I, above, and Sections III, IV and V, each Class A Member's April 1, 2014, to April 1, 2015 winter billing demand shall be the 2013/2014 adjusted winter coincidental metered peak demand.

The 2013/2014 winter coincidental metered peak demand shall be comprised of the average of three 3 consecutive hour coincidental demands occurring at the time of the Joint System highest system peak load taken on up to three separate days, if possible, and occurring between December 1 and the following April 1. Said peak coincidental demands are to be taken or determined from data recorded with full demand response/load management applied according to the then applicable Ripple Control Operating Guide, except that interruption of the loads in Category I (short-term interruptible loads) and not cycled Category II (medium-term interruptible loads) are delayed 75 and 45 minutes respectively into the billing period.

3. Summer Method. After adjustment of summer metered demands in accordance with Section I, above, and Sections III, IV and V, each Class A Member's April 1, 2014, to April 1, 2015, summer billing demand shall be the 2013 adjusted summer coincidental metered peak demand.

The 2013 summer coincidental metered peak demand shall be comprised of the average of all hours of coincidental demands occurring at the time of the Joint System highest system peak load and occurring between June 1 and the following October 1 when full demand response/load management is applied according to the then applicable Ripple Control Operating Guide.

4. Billing Demand Tables. Application of the above adjustments and calculations results in the following tables of billing demands.

FINAL WINTER DEMAND DATA
(April 1, 2014 to April 1, 2015)

	-----------------2013/2014-----------------			
COOPERATIVE	Metered Peak(1)	Demand Waivers	Adjusted Peak	Billing Demand
BELTRAMI	66,920	4,571	62,349	62,349
CASS	164,543	18,796	145,747	145,747
CAVALIER	5,993	0	5,993	5,993
CLEARWATER-POLK	13,020	26	12,994	12,994
NODAK	128,715	371	128,344	128,344
NORTH STAR	17,148	0	17,148	17,148
PKM	16,536	684	15,852	15,852
RED LAKE	22,209	603	21,606	21,606
RED RIVER	19,278	0	19,278	19,278
ROSEAU	19,994	154	19,840	19,840
WILD RICE	42,951	0	42,951	42,951
TOTALS	517,307	25,205	492,102	492,102

(1) Billing candidates from:
01/02/2014 5:00-8:00 PM
01/06/2014 5:00-8:00 PM
01/08/2014 5:00-8:00 PM

FINAL SUMMER DEMAND DATA (April 1, 2014 to April 1, 2015)			
COOPERATIVE	Summer 2013 Metered Peak (Average of 28 hours)	Demand Waivers	Billing Demand
BELTRAMI	54,281	1,660	52,621
CASS	163,878	22,547	141,331
CAVALIER	3,493	0	3,493
CLEARWATER-POLK	8,715	236	8,479
NODAK	131,950	8,448	123,502
NORTH STAR	12,820	789	12,031
PKM	16,730	0	16,730
RED LAKE	18,007	21	17,986
RED RIVER	17,163	425	16,738
ROSEAU	19,679	2,851	16,828
WILD RICE	34,061	1,187	32,874
TOTALS	480,777	38,164	442,613

C. <u>Determination of Number of Transmission kW for Transmission Charge</u>:

The Transmission Charge is based upon the average of the 2013/2014 winter metered demand with the adjustments below:

a. <u>WAPA Customers Adjustment</u>. Same as paragraph I B 1 a.

b. <u>Qualified Cogenerator Standby Service Adjustment</u>. Same as paragraph I B 1 b.

c. <u>Power Factor Adjustment</u>. Same as paragraph I B 1 c.

d. <u>Vickaryous Substation Adjustment</u>. Same as paragraph I B 1 d.

e. <u>Customer Generation Accreditation</u>. Same as paragraph III C.

f. Inadvertent Demand Adjustment. Same as paragraph IV C.

g. Incremental Pricing Plan (IPP) Adjustment. Same as paragraph V E.

and the average of 12 monthly peak loads (12 CP) recorded at the time of Minnkota's monthly peak load during the immediate previous calendar year. In the case where member systems supply supplemental power to WAPA customers (ND State Mill and municipals of Hope and Sharon) the 12 CP applies only to the supplemental load being supplied by the member system.

Application of the above adjustments results in the following table of transmission kW used to calculate the Transmission Demand Charge:

FINAL TRANSMISSION DEMAND DATA
(April 1, 2014 to April 1, 2015)

COOPERATIVE	2013/2014 Metered Peak(1)	Demand Waivers	Adjusted Peak	2013 12 CP	Weighted Average Of Adj. Peak + 12 CP
BELTRAMI	66,920	5	66,915	77,331	72,123
CASS	164,543	18,796	145,747	185,737	165,742
CAVALIER	5,993	0	5,993	5,763	5,878
CLEARWATER-POLK	13,020	26	12,994	13,791	13,393
NODAK	128,715	11	128,704	158,664	143,684
NORTH STAR	17,148	0	17,148	20,667	18,908
PKM	16,536	0	16,536	20,362	18,449
RED LAKE	22,209	19	22,190	22,604	22,397
RED RIVER	19,278	0	19,278	24,183	21,731
ROSEAU	19,994	154	19,840	29,513	24,677
WILD RICE	42,951	0	42,951	50,247	46,599
TOTALS	517,307	19,011	498,296	608,862	553,581

(1) Billing candidates from:
01/02/2014 5:00-8:00 PM
01/06/2014 5:00-8:00 PM
01/08/2014 5:00-8:00 PM

D. Determination of Number of Substations for Substation Charge:

With only those exceptions specifically approved by the Board of Directors, each metering point having one delivery voltage shall be considered one substation.

With only those exceptions specifically approved by the Board of Directors, Class A Members shall pay the monthly charge on substation delivery points completed after March 20, 1984, for not less than 100 months. Any new substations added will be included in the rate calculations in the billing month immediately successive to the month in which the substation is available for service.

Fixed Charge

A fixed charge will be assessed for each substation delivery point. Any combination of Minnkota Class A Members, Northern Municipal Power Agency (NMPA) Systems, WAPA customers or others may combine their loads at a location to share substation charges. In this instance, the fixed charge will be prorated among the users in proportion to their annual kWh usage the previous year. During the initial year of a new joint substation, an equitable proration of the substation charge will be made from the best information available.

The following metering points are considered as only a partial substation when calculating the fixed substation charge.

- The metering point at the Concrete Early Warning Station (CMEWS) shall not be considered a substation.
- The metering points of the American Crystal Sugar Company at Brunsdale and Drayton, North Dakota, shall not be considered a substation.
- The metering points at both the Cass Lake South and Cass Lake North pumping stations near Cass Lake, Minnesota, shall not be considered a substation.
- The metering point at the Wilton pumping station located near Wilton, Minnesota, shall not be considered a substation.
- The metering point at the Joliette pumping station located near Joliette, North Dakota, shall not be considered a substation.
- The metering point at the Potlatch wood products plant located near Rosby, Minnesota, shall be considered ½ of a substation.
- The metering point at the Northwoods wood products plant located near Solway, Minnesota, shall be considered ½ of a substation.
- The metering point at the Crookston pumping station located near Crookston,

Minnesota, shall be considered ½ of a substation.

- The metering point at the Bartlett pumping station located near Bartlett, North Dakota, shall be considered ½ of a substation.

- The metering point at the McMahon pumping station located near Larimore, North Dakota, shall not be considered a substation.

- The metering point of the Pembina Hills Ethanol facility near Walhalla, North Dakota, shall be considered ½ of a substation.

- The metering point at the Brooks pumping station located near Brooks, Minnesota, shall be considered ½ of a substation.

- The metering point at the Steen Substation at the Grand Forks Air Force Base shall be considered two substations.

- The metering point at Simplot in Grand Forks, North Dakota, shall not be considered a substation.

- The metering point at the Cominco Substation near Leal, North Dakota that has two distribution transformers shall be considered one substation.

- The metering point at the Walum Substation near Walum, North Dakota, shall not be considered a substation.

<u>Variable Charge</u>

The variable cost substation charge is based upon the highest 2013 (calendar year) kW peak load at each delivery point. In the case where member systems supply supplemental power to WAPA customers (ND Mill and the municipals of Hope and Sharon), the variable substation charge is based upon the highest monthly load in the 2013 calendar year remaining after the WAPA fixed monthly demand delivery, divided by the appropriate loss multiplier, has been subtracted. Substation peaks created by load switching at Minnkota’s request for equipment maintenance and/or changeouts will be waived. Application of the 2013 peak loads results in the following table of substation demands used to calculate the variable charge:

FINAL SUBSTATION DATA
(April 1, 2014 to April 1, 2015)

COOPERATIVE	2013 Peak Substation kW Demand	Adjustments		Net Substation kW Demand
BELTRAMI	122,492	(7,648)	a	114,844
CASS	297,453	(2,787)	b	294,666
CAVALIER	12,847	(1,955)	c	10,892
CLEARWATER-POLK	21,320	0		21,320
NODAK	266,978	(33,095)	d	233,883
NORTH STAR	35,511	0		35,511
PKM	34,368	0		34,368
RED LAKE	34,293	(1,797)	e	32,496
RED RIVER	39,562	0		39,562
ROSEAU	46,240	0		46,240
WILD RICE	80,417	0		80,417
TOTALS	991,481	(47,282)		944,199

a) Enbridge Pipeline owns both Cass Lake substations and the Wilton substation
b) Fargo Landfill is a generator and not a load plus credit for Barnes Co. wind farm
c) Credit for Langdon wind farm
d) Crystal Sugar leases the Brunsdale and owns the Drayton substations, Enbridge owns the Joliette substation, NSP provides facilities to the Simplot load, the Air Force owns the Concrete PAR substation, the Pembina Hills substation is considered .50 of a substation, the Steen substation is considered as two substations, there is no substation at Walum and credit for Luverne wind farm

	kW
Brunsdale	(20,528)
Concrete PAR	(6,539)
Drayton	(8,716)
Joliette	(3,806)
Luverne wind	(1,356)
Pembina Hills	(228)
Simplot	(13)
Steen	8,299
Walum	(208)
Total	(33,095)

e) Adjustment for Gentilly Creek

II. Qualified Cogenerator Standby Service

A. Definitions:

1. A **Qualified Cogeneration Facility** is defined as a facility which produces electric energy and steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes and which comply with the efficiency and/or fuel source standards of the United States Federal Energy Regulatory Commission Order No. 70.

2. **Qualified Cogeneration Standby Service** is defined as electric capacity and energy provided by Minnkota to Class A Members for resale to consumers operating Qualified Cogeneration Facilities and is available for use only to maintain normal operation of said consumer's manufacturing or production facility during periods of emergency outage or emergency restriction of said consumer's electric generating facilities. The use of standby service for other than emergencies may be allowed on a case-by-case basis with prior approval by Minnkota. Standby service will be available for six months following a major failure of cogenerator equipment to allow adequate time for prudent repair of the cogenerator to occur. An extension of standby service beyond six months must be requested by the customer and will be evaluated for prudency on a month-to-month basis.

3. **MISO (Midcontinent Independent System Operator) Accreditation** is defined as the MISO procedures and standards required to establish a uniform rating of generating equipment. In general, to be accredited generation units must 1) operate synchronously with the system; 2) be tested not less than four continuous hours per year; and 3) be dispatchable at Minnkota's discretion.

B. Applicability:

Qualified Cogeneration Facility Standby Service will be made available by Minnkota to:

1. Class A Member cooperatives for resale to consumer owner/operators of Qualified Cogeneration Facilities.

2. Consumer owner/operators of Qualified Cogeneration Facilities with permission of appropriate Class A Member cooperative.

The obligation of consumers to take or pay for firm electric service shall take precedence over use of said Qualified Cogeneration Facility Standby Service.

C. Rate:

Facilities Charge: A monthly charge based on the total costs of facilities dedicated by Minnkota to provide the requested standby service and/or to receive surplus energy delivered by the cogenerator.

Standby Capacity Charge: Cogenerators that are MISO Accredited

Standby capacity service to be purchased shall be for the lower of a) the maximum cogenerator kW MISO accreditation level or b) the maximum one hour kW electric load level including the kW electric load associated with power station auxiliaries required to operate the facility during use of said standby service, each which is measured during a six month period as defined below. Billings will occur on a monthly basis using the best information available at the beginning of each season, with an adjustment utilizing actual data at the end of each season. Standby capacity service must be purchased for a full season and year-round for any customer who operates anytime during successive seasons.

The rates for standby service to cogenerators which are MISO accredited are:
Summer Period @ $7.00 per kW (June 1 thru September 30)
Winter Period @ $2.00 per kW (October 1 thru May 31)

Cogenerators that are not MISO Accredited

Standby capacity service to be purchased shall be for the lower of a) the maximum one hour kW net generation output of the cogenerator or b) the maximum one hour kW electric load level including the kW electric load associated with power station auxiliaries required to operate the facility during use of said standby service, each which is measured during a six month period as defined below. Billings will occur on a monthly basis using the best information available at the beginning of each season, with an adjustment utilizing actual data at the end of each season. Standby capacity service must be purchased for a full season and year-round for any customer who operates anytime during successive seasons.

Minnkota, at its option, may require the cogenerator to generate at the level of purchased standby service during billing peak periods.

The rates for standby service to cogenerators which are not MISO accredited are:
Summer Period @ $41.00 per kW (June 1 thru September 30)
Winter Period @ $12.00 per kW (October 1 thru May 31)

NOTE 1: There may be special situations where the above kW determinations of standby service are not readily available or applicable. In those situations the assignment of the required kW of standby capacity will be made on a case-by-case basis from the best information available.

Energy Charge: $0.03353 (33.53 mills) per kWh for energy deliveries to the Facility.

Surplus Energy Payment: Minnkota will pay $0.03353 (33.53 mills) per kWh for cogenerated electric energy that is in excess of the electric load required for operation of the Facility.

Credits:

a. The coincident metered demand associated with each Qualified Facility of each Class A Member will be reduced by an amount equal to the difference between the amount of standby capacity purchased and the output of the cogenerator, with the resultant metered demand to be not less than zero.

b. The monthly facilities and standby capacity charges herein provided for will be waived for months that Minnkota receives demand charge payments from the Class A Member in accordance with the Wholesale Power Rate on behalf of the Qualified Cogeneration Facility.

c. Class A Member Billing Demand obligations created by the supplying of Qualified Cogeneration Standby Service are waived.

III. Distributed Generation

A. Qualifications:

1. Customers must meet the following criteria:

   a. Generation must be connected synchronously to Minnkota's transmission system and/or cooperative's distribution system.

   b. Annually perform a test of the generation at maximum output.

   c. Generator(s) must be capable of operating a minimum of four consecutive hours and a minimum of five annual events.

   d. Provide Minnkota with generation performance data, upon request.

   e. Maintain generator(s) in a condition that meets good utility practice.

   f. Minnkota retains the right to dispatch the generator(s) as needed.

   g. Enter into a contractual agreement with the distribution cooperative and/or Minnkota.

2. The distribution cooperative must allow the customer and Minnkota to utilize its distribution facilities to facilitate the transfer of power from the generator(s) to and from Minnkota.

B. Rate Schedule:

1. Capacity:

a. Generator(s) not supplying their load needs - Minnkota will pay the customer $21.00 per kW per year for MISO accredited generation if the individual generator capacity is 500 kW or larger.

b. Generator(s) supplying their load needs - Minnkota will pay the customer $21.00 per kW per year for MISO accredited generation that is in excess of 115% of the customer's one-hour kW peak load if the individual generator excess capacity is 500 kW or larger.

2. Energy: Minnkota will pay the customer for all net kWh generated. The distributed generation energy rate is Minnkota's avoided cost which is currently based on the wholesale energy market conditions.

Adjustments to the distributed generation rate may be done on a case-by-case basis depending on the value the energy provides Minnkota. The criteria considered include but are not inclusive to: the ability/limits to dispatch the generator(s), on-peak kWh production versus off-peak kWh production, the generator(s) capacity factor, Minnkota's needs for capacity and energy, etc.

Distributed Generation Energy Rate: $0.025 per kWh

3. The distributed generation capacity and energy rate is reviewed annually and is subject to change on an annual basis.

C. Metered Demand Credit for Accredited Generator:

1. The coincidental metered substation demand of the distribution cooperative will be credited by an amount equal to the accredited generation divided by 115% but not exceeding the customer load coincidentally metered during the billing peaks.

IV. Inadvertent Demand Adjustment

This program is an option for offsetting possible financial losses caused by the malfunction of load management facilities during billing periods. The program can mitigate the impact of large unanticipated inadvertent wholesale power demand billings on the Class A Member's system and/or its larger commercial and industrial consumers which are metered with recording demand meters.

A. Qualifications

1. Each load must meet the following criteria:

a. It must have an adequately installed and properly maintained directly connected automatic load control system.

b. It must be metered by a time synchronized, continuous operation, one hour or less interval, demand recorder.

B. Rate Schedule

1. The Class A Member must pay Minnkota for the kW level of each selected qualified load that could increase the Class A Member's seasonal billing demand should load management fail to curtail the insured load(s). In the case of multiple generators at the same site, the individual load associated with each generator must be qualified separately.

Season	Rate	Payment Due Date
Summer 2014	$1.95/kW	May 15, 2014
Winter 2014/2015	$2.48/kW	November 15, 2014

2. The Class A Member shall supply the name of each qualified load and the estimated kW demand of each load along with the payment in accordance with the rate schedule above.

C. Metered Demand Credit

1. Upon acceptable demonstration by the Class A Member of the magnitude of kW of qualified load that failed to be controlled, Minnkota will subtract from the Class A Member's affected hourly metered seasonal coincidental demands used for summer, winter and transmission billing demand calculations a kW amount equal to 1.08 x 0.667 times any portion of the qualified load which inadvertently and unintentionally became a demand obligation through human error or failure of load control equipment located at the load site.

V. Incremental Pricing Plan (IPP)

This program is available to Class A Members with commercial customers, irrigation customers or Heating Demand Waiver (HDW) generators that may choose to pay a supplemental payment in lieu of load control or generation during certain load control events.

A. Qualifications

1. Each commercial load, irrigation load or HDW generator must be metered by a time synchronized, continuous operation, one-hour or less interval demand recorder.

2. Individual commercial and irrigation loads that participate must be placed into the double order specific to the Incremental Pricing Plan as documented in the Ripple Operating Guide.

3. Each HDW generator must be capable of being MISO accredited as Minnkota

generation in both the summer and winter seasons. The HDW generators would be run under Minnkota's control and discretion similar to other Minnkota MISO accredited generation.

B. Control/Operational Criteria

1. The commercial and irrigation double orders specific to the Incremental Pricing Plan will not be controlled unless:

   a. Load control is required because Minnkota is reaching a capacity limit.

   b. Minnkota is buying energy and the wholesale market price for that purchased energy would lead to an average purchased energy price greater than the pre-determined average for that season.

   c. Load control is required for Schedule L certification.

2. The HDW generators will be considered in the HDW yellow zone, when a supplemental energy payment can be made in lieu of operation, for the same number of hours as the seasonal average control hours of the dual fuel furnaces.

3. Minnkota will, during HDW yellow zone time periods, purchase energy from the wholesale market in a quantity equal to the lower of the total generation accredited capability or the HDW customer load. The energy quantity will be agreed to prior to the start of a winter season. Energy will be purchased at an average winter season price that will be equal to the IPP commercial customer price.

C. Data Reporting

1. Each Class A Member participating in this program will report the hourly coincidental metered demand data and energy data for each qualifying commercial and irrigation customer for all load control hours normally scheduled for that load as follows:

Season	Demand Data	Supplemental Energy Data
Winter	3/10/14	5/1/14
Summer	11/15/14	11/15/14

D. Rate Schedule

1. The Class A Member must pay Minnkota a supplemental charge of up to 9.5¢/kWh for commercial loads and 12¢/kWh for irrigation loads for kWh recorded on the hourly coincidental meter(s) during all load control events normally scheduled for the qualifying commercial and irrigation customer(s). The recorded kWh will start at the beginning of the clock quarter hour after activation begins and ending at the beginning of the clock quarter hour before the activation ends.

2. The Class A member must pay Minnkota a supplemental charge of up to 9.5¢/kWh for the quantity of kWh calculated as the HDW yellow zone periods (same number of hours as the seasonal average of the dual fuel furnaces) times the lower of the total generation accredited capability or the HDW customer load calculated as if the program continued to exist.

E. Metered Demand Credit

1. Minnkota will credit each Class A Member's hourly winter and summer coincidental billing demand based on the hourly metered demand supplied in Paragraph C above except for the hours when control is required for capacity limitation, to avoid higher cost energy purchases or Schedule L certification as defined in Paragraph B above.

2. Minnkota will credit each Class A Member's hourly winter coincidental billing demand for HDW generation by the lesser of:

   a. The effective MISO accredited generation level of the generators, or

   b. The total load attributable to the Class A Member's demand waiver customers who would have been eligible for the Demand Waiver Program had that program continued to exist.

F. HDW Generator Fuel Pricing

1. Minnkota will pay each Class A Member when Minnkota operates the HDW generation for its own purpose at a rate of the actual fuel cost plus 25%.

VI. General

A. Feasibility of New or Expanded Substation Delivery Points:

1. If normal revenue expected to be derived from a new or expanded dedicated substation delivery point for a large commercial/industrial load is projected over a reasonable length of time not to adequately cover ownership and operating costs, Minnkota, on a case-by-case basis, may require a minimum substation and demand charge, a contribution in aid of construction, minimum annual revenue requirement or other special arrangement to assure an adequate return on the facility investment.

2. A request for a new substation delivery point that does not meet Minnkota's need/justification standards (example: requested before Minnkota would normally construct such substation delivery point) may be constructed under the general provisions that include:

   a. Minnkota would design, construct, own and maintain the facility.

   b. To assure an adequate return of facility investment, the member cooperative(s) and Minnkota will enter into an appropriate agreement of one of the following options:

1. Contribution in aid of construction
2. Minimum annual revenue requirement
   - The cost of the new facilities would be amortized over 33 years at the then current borrowing rate. This value becomes the minimum annual revenue requirement and is divided by 12 to become the minimum monthly revenue requirement.
   - Beginning the first month following energization and each month thereafter, Minnkota will bill the requesting distribution cooperative for the difference between the minimum monthly revenue requirement and the then current monthly fixed substation charge until such time the new facilities meet the Minnkota need/justification standards.
   - Minnkota will determine the load level that would meet the Minnkota need/justification standards prior to construction of the requested facilities.
3. Other special arrangement

B. <u>Service Conditions</u>:

Minnkota reserves the right to require Class A Members to correct any condition on its system or on the systems of its members which causes a hazard to Minnkota's facilities and personnel, or to the quality of service provided by Minnkota to others. All motors, appliances or equipment connected to the Class A Member's systems must be so designed, installed and operated as not to cause undue disturbance to others nor to handicap Minnkota in maintaining proper system conditions.

VII. <u>Wind Subscription Program</u>

This program provides Minnkota member systems the source to purchase wind energy green tags or renewable energy credits (RECs) for resale to their customers. The wind subscriptions are sold in 100 kWh per month blocks and are M-RETS (Midwest Renewable Energy Tracking System) certified.

The purchase commitment is on a month-by-month basis. The 100 kWh blocks will be purchased monthly until the member system notifies Minnkota of any changes (increases or decreases) in the quantity of kWh blocks purchased. All notifications for changes in the monthly number of blocks purchased must be received by Minnkota 10 days prior to the first day of the month.

Wind Subscription Rate: $0.30 per 100 kWh block per month.

APPENDIX D

Form EIA-861

US Department of Energy Energy Information Administration Form EIA-861 (2010)	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2017

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

Contact Kay Schraeder
Title: Accountant

Phone: (701) 795-4266 FAX: (701) 795-4215 Email: kschraeder@minnkota.com

REPORT FOR: Minnkota Power Coop, Inc 12658
REPORTING PERIOD: 2013

Logged By / Date:
Logged In: ☐ Receipt Date (mm/dd/yyyy):

Supervisor Craig Rustad
Title: Accounting Manager

Phone: (701) 795-4261 FAX: (701) 795-4215 Email: crustad@minnkota.com

1	Legal Name of Industry Participant	Minnkota Power Coop, Inc	**Submission Status/Date:** Submitted 06/18/2014
2	Current Address of Principal Business Office	1822 Mill Road Grand Forks ND 58203 0000	
3	Preparer's Legal Name Operator (if different than line 1)		
4	Current Address of Preparer's Office (if different than line 2)		
5	Respondent Type (Check One)	☐ Federal ☐ Political Subdivision ☐ Municipal Marketing Authority ☒ Cooperative ☐ Independent Power Producer or Qualifying Facility	☐ State ☐ Municipal ☐ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Wholesale Power Marketer ☐ Transmission

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Jorge Luna-Camara Phone: (202) 586-3945 jorge.luna-camara@eia.gov **Stephen Scott** Phone: (202) 586-5140 Email: stephen.scott@eia.gov

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 2, PART A. GENERAL INFORMATION

LINE NO.		
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] NPCC [ ] SPP [ ] FRCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] WECC [x] MRO [ ] SERC
2	Name of RTO or ISO	[ ] California ISO [ ] Southwest Power Pool [ ] Electric Reliability Council of Texas [X] Midwest ISO [ ] PJM Interconnection [ ] ISO New England [ ] New York ISO [ ] None
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO
4	Did Your Company Operate Generating Plants(s)?	[x] Yes [ ] No
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant [ ] Buying distribution on other electrical system [x] Transmission [x] Wholesale power marketing [x] Buying transmission services on other electrical system [ ] Retail power marketing [ ] Distribution using owned/leased electric wires [ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 690.2 Prior Year 602.9 Winter (Megawatts) 926.3 Prior Year 861.1
	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[ ] Yes [x] No
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[ ] Yes [x] No
7	If "Yes", Please Provide Additional Contact Information	Name: Title: Telephone: - - Fax: - - Email:

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 2. PART B ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	1,704,521	11	Sales to Ultimate Consumers	
2	Purchases from Electricity Suppliers	3,951,673	12	Sales For Resale	5,538,211
3	Exchanged Received (In)		13	Energy Furnished Without Charge	55,351
4	Exchanged Delivered (Out)	28,318	14	Energy Consumed By Respondent Without Charge	6,787
5	Exchanged Net	-28,318			
6	Wheeled Received (In)	23,955			
7	Wheeled Delivered (Out)	22,388	15	Total Energy Losses (positive number)	29,094
8	Wheeled Net	1,567			
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	5,629,443	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	5,629,443

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 2, PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	
2	1 Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	309,726.0
4	Electric Credits/Other Adjustments	$	
5	Revenue from Transmission	$	
6	Other Electric Operating Revenue	$	8,036.0
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	317,762.0

REPORT FOR: Minnkota Power Coop, Inc

REPORT PERIOD ENDING:

SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory

1	Total Number of Distribution Circuits	
2	Number of Distribution Circuits applying distribution automation technol	

REPORT FOR: Minnkota Power Coop, Inc

REPORT PERIOD ENDING:

SCHEDULE 3. PART B
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

		Yes	No
1	Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A.		x
2	Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes,complete Part B. If No, go to complete PArt C.		x

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State
3a.	SAIDI value including Major Event days	
3b.	SAIDI value excluding Major Event days	
4	SAIDI value including Major Event days minus loss of supply	
5a.	SAIFI value including Major Event days	
5b.	SAIFI value excluding Major Event days	
6.	SAIFI value including Major Event days minus loss of supply	
7.	Total number of customers used in these calculations	
8.	At what voltage do you distinguish the distribution system from the supply system? (kV)	
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[ ] Yes [x] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

REPORT FOR: Minnkota Power Coop, Inc

REPORT PERIOD ENDING:

Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	
13. Do you include inactive accounts?	☐ Yes ☒ No
14. How do you define momentary interruptions	☐ Less than 1 min. ☐ Less than 5 min. ☐ Other
15. At what voltage do you distinguish the distribution system from the supply system?	kv
16. Is information about customer outages recorded automatically?	☐ Yes ☒ No

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 4, PART -A . SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

State	**Balancing Authority**	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?		☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?		N automatic	N automatic	N automatic	N automatic	
		N proceeding	N proceeding	N proceeding	N proceeding	
Cents/Kwh						

State						
Revenue (thousand dollars)						
Megawatthours						
Number of Customers						
Are your rates decoupled?						
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?						
Cents/Kwh						

Total

Revenue (thousand dollars)

Megawatthours

Number of Customers

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 4, PART -B . SALES TO ULTIMATE CUSTOMERS. ENERGY -- ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total

Revenue (thousand dollars)

Megawatthours

Number of Customers

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 4, PART -C . SALES TO ULTIMATE CUSTOMERS. DELIVERY -- ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 4, PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

REPORT FOR: Minnkota Power Coop, Inc Utility Id 12658

REPORTING PERIOD: 2013

SCHEDULE 5 MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 6 PART A. ENERGY EFFICIENCY PROGRAMS

Schedule 6. Part A. Adjusted Gross Energy and Demand Savings -- Energy Efficiency

State/Territory **Balancing Authority**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)					
2	Peak Demand Savings (MW)					
	Increment Life Cycle Savings					
3	Energy Savings (MWh)					
4	Peake Demand Savings (MW)					
	Reporting Year Incremental Costs					
5	Customer Incentives					
6	All other costs					
	Incremental Life Sycle Costs					
7	Customer Incentives					
8	All other costs					
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life					

Please provide website address to your energy efficiency program reports:

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

Schedule 6. Part B. Energy and Demand Savings -- Demand Response

Reporting Year Savings

State/Territory	Balancing Authority	(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled					
2	Energy Savings (Mwh)					
3	Potenetial Peak Demand Savings (MW)					
4	Actual Peak Demand Savings (MW)					

Schedule 6. Part B. Program Costs -- Demand Responses (Thousand Dollars)

Reporting Yearly Costs

5	Customer Incentives	
6	All other costs	
7	If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?	

REPORT FOR: Minnkota Power Coop, Inc

REPORT PERIOD ENDING:

SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory **Balancing Authority**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class					

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customer are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	Yes [x] No	Yes [x] No	Yes [x] No	Yes [x] No
3	Real TimePricing	Yes [x] No	Yes [x] No	Yes [x] No	Yes [x] No
4	Variable Peak Pricing	Yes [x] No	Yes [x] No	Yes [x] No	Yes [x] No
5	Critical Peak Pricing	Yes [x] No	Yes [x] No	Yes [x] No	Yes [x] No
6	Critical Peak Rebate	Yes [x] No	Yes [x] No	Yes [x] No	Yes [x] No

REPORT FOR Minnkota Power Coop, Inc

REPORT PERIOD ENDING

SCHEDULE 6, PART D ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **Balancing Authority**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters					
2	Number of AMI Meters					
3	Number of AMI Meters with home area network (HAN) gateway enabled					
4	Number of non AMR/AMI Meters					
5	Total Number of Meters (All Types), line 1+2+4					
6	Energy Served Through AMI					
7	Number of Customers able to access daily energy usage through a webportal or other electronic means					
8	Number of customers with direct load control					

REPORT FOR Minnkota Power Coop, Inc

REPORT PERIOD ENDING

SCHEDULE 7. PART A. NET METERING

Net Metering program allow customers to sell excess power they generate back to the electrical grid to offset consumption. Provide the information about programs by Statem balancing authority, customer class, and technology for all net metering applications.

State	Balancing Authority	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
	Installed Net Metering Capacity (MW)					
Photololatic	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Wind	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Other	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					
	Installed Net Metering Capacity (MW)					
Total	Number of Net Metering Customers					
	If Available, Enter the Electric Energy Sold Back tot he Utility (Mwh)					

REPORT FOR Minnkota Power Coop, Inc

REPORT PERIOD ENDING

SCHEDULE 7. PART B. DISTRIBUTED AND DISPERSED GENERATION

If your company owns and/or operates a distribution system, please report information on known distributed generation capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

State | **Balancing Authority**

Distributed Generators (Commercial and Industrial Grid Connected/Synchronized Generators) (a)	< 1MW	Dispersed Generators (Commercial and Industrial Generators Not Connected/Synchronized to the Grid) (b)	< 1MW
1. Number of generators		1. Number of generators	
2. Total combined capacity (MW)		2. Total combined capacity (MW)	
3. Capacity that consists of backup-only units		3. Capacity that consists of backup-only units	
4 Capacity owned by respondent		4. Capacity owned by respondent	
5. Nature of data reported	☐ Actual ☐ Estimated	5. Nature of data reported	☐ Actual ☐ Estimated

Capacity by Technology (MW)

1. Internal combustion/reciprocating engines		1. Internal combustion/reciprocating engines	
2. Combustion turbine(s)		2. Combustion turbine(s)	
3. Steam turbine(s)		3. Steam turbine(s)	
4. Hydroelectric		4. Hydroelectric	
5. Wind turbine(s)		5. Wind turbine(s)	
6, Photovoltaic		6. Photovoltaic	
7. Storage		7. Storage	
8. Other		8. Other	
9. Total		9. Total	
10. Nature of data reported	☐ Actual ☐ Estimated	10. Nature of data reported	☐ Actual ☐ Estimated

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	-				

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)
6				We will no longer be reporting this information as our distributions cooperatives are reporting it.

REPORT FOR: Minnkota Power Coop, Inc 12658

REPORT PERIOD ENDING: 2013

EIA861 ERROR LOG

Part	State	Error	No.	Error Description/Override Comment	Type	Override
2	C	MN	204	Your utility reported Residential green pricing customers last year, but not this year. This edit is misfiring as it is referencing a schedule that is no longer on the EIA-861 form	W	
2	C	ND	204	Your utility reported Residential green pricing customers last year, but not this year. This edit is misfiring as it is referencing a schedule that is no longer on the EIA-861 form	W	
2	C	ND	205	Your utility reported Commercial green pricing customers last year, but not this year. This edit is misfiring as it is referencing a schedule that is no longer on the EIA-861 form	W	

APPENDIX E

RUS Form 12

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION ND0020
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD ENDED December, 2013 (Prepared with Audited Dat
INSTRUCTIONS - See help in the online application.	BORROWER NAME Minnkota Power Cooperative, Inc.

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552)

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

☒ All of the obligations under the RUS loan documents have been fulfilled in all material respects.

3/25/14
DATE

☐ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION ND0020 PERIOD ENDED December, 2013
INSTRUCTIONS - See help in the online application.	

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE			THIS MONTH (*d*)
	LAST YEAR (*a*)	THIS YEAR (*b*)	BUDGET (*c*)	
1. Electric Energy Revenues	281,053,057	309,726,155		
2. Income From Leased Property (Net)				
3. Other Operating Revenue and Income	7,491,992	8,035,599		
4. Total Operation Revenues & Patronage Capital *(1 thru 3)*	288,545,049	317,761,754		
5. Operating Expense – Production - Excluding Fuel	15,929,458	14,670,621		
6. Operating Expense – Production - Fuel	28,337,742	28,638,357		
7. Operating Expense – Other Power Supply	166,056,030	188,560,310		
8. Operating Expense – Transmission	17,038,393	18,654,294		
9. Operating Expense – RTO/ISO				
10. Operating Expense – Distribution	4,468,894	3,936,349		
11. Operating Expense – Customer Accounts				
12. Operating Expense – Customer Service & Information				
13. Operating Expense – Sales	51,250	51,313		
14. Operating Expense – Administrative & General	9,645,260	11,642,320		
15. Total Operation Expense *(5 thru 14)*	241,527,027	266,153,564		
16. Maintenance Expense – Production	8,815,544	12,627,813		
17. Maintenance Expense – Transmission	4,552,383	5,348,249		
18. Maintenance Expense – RTO/ISO				
19. Maintenance Expense – Distribution	1,500,270	1,983,108		
20. Maintenance Expense – General Plant	630,692	734,003		
21. Total Maintenance Expense *(16 thru 20)*	15,498,889	20,693,173		
22. Depreciation and Amortization Expense	14,025,085	14,945,433		
23. Taxes				
24. Interest on Long-Term Debt	19,004,744	21,686,363		
25. Interest Charged to Construction – Credit	(4,308,995)	(6,710,473)		
26. Other Interest Expense	213,873	208,274		
27. Asset Retirement Obligations				
28. Other Deductions	31,294	86,543		
29. Total Cost Of Electric Service *(15 + 21 thru 28)*	285,991,917	317,062,877		
30. Operating Margins *(4 less 29)*	2,553,132	698,877		
31. Interest Income	1,015,778	1,837,021		
32. Allowance For Funds Used During Construction				
33. Income (Loss) from Equity Investments				
34. Other Non-operating Income (Net)	2,086,254	2,918,191		
35. Generation & Transmission Capital Credits				
36. Other Capital Credits and Patronage Dividends	1,844,836	2,045,911		
37. Extraordinary Items				
38. Net Patronage Capital Or Margins *(30 thru 37)*	7,500,000	7,500,000		

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION ND0020 PERIOD ENDED December, 2013
INSTRUCTIONS – See help in the online application.	

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS			LIABILITIES AND OTHER CREDITS		
1.	Total Utility Plant in Service	683,160,242	33.	Memberships	1,141
2.	Construction Work in Progress	315,446,578	34.	Patronage Capital	
3.	**Total Utility Plant** *(1 + 2)*	998,606,820		a. Assigned and Assignable	29,774,975
4.	Accum. Provision for Depreciation and Amortization	183,075,391		b. Retired This year	0
				c. Retired Prior years	6,765,700
5.	**Net Utility Plant** *(3 - 4)*	815,531,429		**d. Net Patronage Capital** *(a - b - c)*	23,009,275
6.	Non-Utility Property (Net)	0	35.	Operating Margins - Prior Years	0
7.	Investments in Subsidiary Companies	0	36.	Operating Margin - Current Year	698,877
8.	Invest. in Assoc. Org. - Patronage Capital	48,911	37.	Non-Operating Margins	6,801,123
9.	Invest. in Assoc. Org. - Other - General Funds	0	38.	Other Margins and Equities	78,342,782
10.	Invest. in Assoc. Org. - Other - Nongeneral Funds	0	**39.**	**Total Margins & Equities** *(33 +34d thru 38)*	108,853,198
11.	Investments in Economic Development Projects	0			
12.	Other Investments	6,966,063	40.	Long-Term Debt - RUS (Net)	2,710,737
13.	Special Funds	0	41.	Long-Term Debt - FFB - RUS Guaranteed	561,834,253
14.	**Total Other Property And Investments** *(6 thru 13)*	7,014,974	42.	Long-Term Debt - Other - RUS Guaranteed	0
			43.	Long-Term Debt - Other (Net)	187,190,133
15.	Cash - General Funds	194,273	44.	Long-Term Debt - RUS - Econ. Devel. (Net)	0
16.	Cash - Construction Funds - Trustee	0	45.	Payments – Unapplied	40,000,000
17.	Special Deposits	0	**46.**	**Total Long-Term Debt** *(40 thru 44 - 45)*	711,735,123
18.	Temporary Investments	1,252,428	47.	Obligations Under Capital Leases Noncurrent	0
19.	Notes Receivable (Net)	0	48.	Accumulated Operating Provisions and Asset Retirement Obligations	7,681,267
20.	Accounts Receivable - Sales of Energy (Net)	38,903,075	**49.**	**Total Other NonCurrent Liabilities** *(47 + 48)*	7,681,267
21.	Accounts Receivable - Other (Net)	10,871,555			
22.	Fuel Stock	5,904,411	50.	Notes Payable	1,617,000
23.	Renewable Energy Credits	0	51.	Accounts Payable	40,343,174
24.	Materials and Supplies - Other	17,297,392	52.	Current Maturities Long-Term Debt	12,665,985
25.	Prepayments	6,044,187	53.	Current Maturities Long-Term Debt - Rural Devel.	0
26.	Other Current and Accrued Assets	0	54.	Current Maturities Capital Leases	0
27.	**Total Current And Accrued Assets** *(15 thru 26)*	80,467,321	55.	Taxes Accrued	3,441,111
			56.	Interest Accrued	479,310
28.	Unamortized Debt Discount & Extraordinary Property Losses	0	57.	Other Current and Accrued Liabilities	6,207,103
29.	Regulatory Assets	2,313,973	**58.**	**Total Current & Accrued Liabilities** *(50 thru 57)*	64,753,683
30.	Other Deferred Debits	3,681,140	59.	Deferred Credits	15,985,566
31.	Accumulated Deferred Income Taxes	0	60.	Accumulated Deferred Income Taxes	0
32.	**Total Assets and Other Debits** *(5+14+27 thru 31)*	909,008,837	**61.**	**Total Liabilities and Other Credits** *(39 + 46 + 49 + 58 thru 60)*	909,008,837

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

SECTION C. NOTES TO FINANCIAL STATEMENTS

Deferred debits (lines 29 & 30 of the Balance Sheet) include the following:

Young 1 deferred outage expenses*	$ 2,284,077
Coyote deferred outage expenses**	29,896
Total Regulatory Assets	$ 2,313,973
Deferred pension costs	3,681,140
Total	$ 5,995,113

* In accordance with SFAS 71 and approved by RUS in 1997

** In accordance with SFAS 71 and approved by RUS in 2005

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

SECTION C. CERTIFICATION LOAN DEFAULT NOTES

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

PART B SE - SALES OF ELECTRICITY

Sale No.	Name Of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
1	Ultimate Consumer(s)							
2	Beltrami Electric Coop, Inc		LF			59	86	77
3	Cass County Electric Coop, Inc (ND0011)	ND0011	LF			133	214	187
4	Cavalier Rural Elec Coop, Inc (ND0038)	ND0038	LF			6	8	6
5	Clearwater-Polk Elec Coop Inc		LF			12	15	14
6	Nodak Electric Coop, Inc (ND0019)	ND0019	LF			126	194	157
7	North Star Electric Coop, Inc (MN0095)	MN0095	LF			16	22	21
8	P K M Electric Coop, Inc (MN0087)	MN0087	LF			15	23	21
9	Red Lake Electric Coop, Inc (MN0075)	MN0075	LF			20	24	23
10	Red River Valley Coop Pwr Assn (MN0074)	MN0074	LF			18	26	25
11	Roseau Electric Coop, Inc		LF			18	32	29
12	Wild Rice Electric Coop, Inc (MN0082)	MN0082	LF			41	54	51
13	Midwest Independent Transmission System Operator, Inc. (IN)		AD					
14	Minnesota Power & Light Co		OS					
15	Xcel Energy		OS					
16	*Adjustments		AD					
17	*Miscellaneous		AD					
18	Basin Electric Power Coop (ND0045)	ND0045	OS					
UC	Total for Ultimate Consumer(s)							
Dist	Total for Distribution Borrowers					375	565	491
G&T	Total for G&T Borrowers					0	0	0
Other	Total for Other					89	133	120
Total	Grand Total					464	698	611

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

PART B SE - SALES OF ELECTRICITY

Sale No	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1					
2	474,704	11,731,144	19,458,677	1,167,666	32,357,487
3	1,158,278	27,113,197	47,469,124	2,880,849	77,463,170
4	41,672	1,023,295	1,707,555	160,159	2,891,009
5	81,574	2,126,809	3,344,279	216,777	5,687,865
6	1,107,255	24,733,194	45,829,015	2,099,685	72,661,894
7	124,125	2,885,870	5,089,283	358,637	8,333,790
8	132,409	2,902,886	5,427,370	426,942	8,757,198
9	137,902	3,783,353	5,653,039	330,357	9,766,749
10	141,858	3,481,576	5,815,629	672,780	9,969,985
11	178,130	3,607,233	7,301,610	457,873	11,366,716
12	295,726	7,636,847	12,123,319	754,269	20,514,435
13	1,043,702		27,359,543		27,359,543
14	37,800		1,032,360		1,032,360
15	387,925	10,523,203	7,261,197	2,137,956	19,922,356
16	181,998			491,584	491,584
17				1,226,770	1,226,770
18	13,153			311,851	311,851
UC					
Dist	3,139,225	73,560,218	129,114,334	7,683,678	210,358,230
G&T	13,153	0	0	311,851	311,851
Other	2,385,833	27,988,389	65,757,666	5,698,626	99,444,681
Total	5,538,211	101,548,607	194,872,000	13,694,155	310,114,762

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

PART B SE - SALES OF ELECTRICITY

Sale No	Comments
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	Revenue 12/20 - 12/31/13
17	Revenue Deferral
18	
UC	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

PART B PP - PURCHASED POWER

Purchase No.	Name Of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand () (h)
1	Manitoba Hydro		OS					
2	Northern Municipal Power Agncy		LF					
3	Square Butte Elec Cooperative (ND0048)	ND0048	LF					
4	Western Area Power Admin		RQ			86,801		
5	Midwest Independent Transmission System Operator, Inc. (IN)		OS					
6	*Miscellaneous		OS					
7	*Miscellaneous		OS					
8	*Miscellaneous		OS					
9	*Miscellaneous		OS					
10	*Miscellaneous		OS					
11	*Miscellaneous		OS					
12	*Miscellaneous		OS					
13	*Miscellaneous		OS					
14	*Miscellaneous		OS					
15	*Miscellaneous		OS					
Dist	Total for Distribution Borrowers					0	0	0
G&T	Total for G&T Borrowers					0	0	0
Other	Total for Other					86,801	0	0
Total	Grand Total					86,801	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

PART B PP - PURCHASED POWER

Purchase No	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	7,707					559,700	559,700
2	319,483					18,556,014	18,556,014
3	1,255,436					71,865,516	71,865,516
4	534,212			7,917,842	8,829,729	3,857	16,751,428
5	663,643					27,155,652	27,155,652
6	159					5,233	5,233
7	41					291,503	291,503
8						19,632	19,632
9						38,434	38,434
10	5,123					276,802	276,802
11						18,379	18,379
12	16					848	848
13						82,260	82,260
14	1,165,853					52,936,807	52,936,807
15						2,102	2,102
Dist	0	0	0	0	0	0	0
G&T	1,255,436	0	0	0	0	71,865,516	71,865,516
Other	2,696,237	0	0	7,917,842	8,829,729	99,947,223	116,694,794
Total	3,951,673	0	0	7,917,842	8,829,729	171,812,739	188,560,310

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

PART B PP - PURCHASED POWER

Purchase No	Comments
1	
2	
3	
4	
5	
6	American Crystal
7	Cap Chg & Municipal Generation
8	Butler & Shanley
9	Devils Lake East Outlet
10	Fargo Landfill
11	MRets Fees
12	Polk County Solid Waste
13	Summer Capacity - Cass
14	Wind PPS's
15	Wind Generation Credits

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application	PERIOD ENDED December, 2013

PART C RE - RENEWABLE GENERATING PLANT SUMMARY

Plant Name (a)	Prime Mover (b)	Primary Renewable Fuel Type (c)	Renewable Fuel (%) (d)	Capacity (kW) (e)	Net Generation (MWh) (f)	Capacity Factor (%) (g)
Infinity-Valley City	Large Wind	Wind	100.00	900.0	2370.0	30.10
Infinity - Petersburg	Large Wind	Wind	100.00	900.0	2700.0	34.20
Total:				1800.0	5070.0	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application	PERIOD ENDED December, 2013

PART C RE - RENEWABLE GENERATING PLANT SUMMARY

Plant Name (a)	Number of Employees (h)	Total O&M Cost (mils/Net kWh) (i)	Power Cost (mils/Net kWh) (j)	Total Investment ($1,000) (k)	Percentage Ownership (%) (l)	RUS Funding ($1,000) (m)
Infinity-Valley City	0	15	37	1,005,666	100	0
Infinity - Petersburg	0	14	32	1,006,287	100	0
Total:	0	29	69	2,011,953		0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application	PERIOD ENDED December, 2013

PART C RE - RENEWABLE GENERATING PLANT SUMMARY

Plant Name	Comments
Infinity-Valley City	
Infinity - Petersburg	

rcUNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

SOURCES OF ENERGY *(a)*	**NO. OF PLANTS** *(b)*	**CAPACITY (kW)** *(c)*	**NET ENERGY RECIEVED BY SYSTEM (MWh)** *(d)*	**COST ($)** *(e)*
Generated in Own Plant ***(Details on Parts D, E, F IC, F CC, and G)***				
1. Fossil Steam	1	256,200	1,699,451	75,214,983
2. Nuclear	0	0	0	0
3. Hydro	0	0	0	0
4. Combined Cycle	0	0	0	0
5. Internal Combustion	2	0	0	0
6. Other	0	0	5,070	173,747
7. Total in Own Plant ***(1 thru 6)***	3	256,200	1,704,521	75,388,730
Purchased Power				
8. Total Purchased Power			3,951,673	188,560,310
Interchanged Power				
9. Received Into System (Gross)			0	0
10. Delivered Out of System (Gross)			28,318	0
11. Net Interchange ***(9 - 10)***			(28,318)	0
Transmission For or By Others - (Wheeling)				
12. Received Into System			23,955	0
13. Delivered Out of System			22,388	0
14. Net Energy Wheeled ***(12 - 13)***			1,567	0
15. Total Energy Available for Sale ***(7 + 8 + 11 + 14)***			5,629,443	
Distribution of Energy				
16. Total Sales			5,538,211	
17. Energy Furnished to Others Without Charge			55,351	
18. Energy Used by Borrower *(Excluding Station Use)*			6,787	
19. Total Energy Accounted For ***(16 thru 18)***			5,600,349	
Losses				
20. Energy Losses - MWh ***(15 - 19)***			29,094	
21. Energy Losses - Percentage ***((20 / 15) * 100)***			.52 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION: ND0020

PLANT: Milton R. Young #1

PERIOD ENDED: December, 2013

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: SCHED. (j)	UNSCH. (k)
1.	1	7	2,930,830.00	486.00				7,506	0	1,109	145
2.											
3.											
4.											
5.											
6.	Total	7	2,930,830	486.00	0.00	0.00		7,506	0	1,109	145
7.	Average BTU		6,760	140,000.00							
8.	Total BTU (10^6)		19,812,411.00	68,040			19,880,451				
9.	Total Del. Cost ($)		27,085,313	1,553,044.00							

SECTION A. BOILERS/TURBINES (*Continued*)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	256,200	1,896,853.00	
2.				
3.				
4.				
5.				
6.	Total	256,200	1,896,853.00	10,481
7.	Station Service (MWh)		197,402.00	
8.	Net Generation (MWh)		1,699,451.00	11,698.16
9.	Station Service (%)		10.41	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	65
2.	No. Employees Part-Time	0
3.	**Total Employee Hours Worked**	132,986
4.	Operating Plant Payroll ($)	2,432,181
5.	Maintenance Plant Payroll ($)	2,121,354
6.	Other Accts. Plant Payroll ($)	922,119
7.	**Total Plant Payroll ($)**	5,475,654

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	77.06%
2.	Plant Factor (%)	84.52%
3.	Running Plant Capacity Factor (%)	98.64%
4.	15 Minute Gross Max. Demand (kW)	281,000
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	694,582		
2.	Fuel, Coal	501.1	27,085,313		
3.	Fuel, Oil	501.2	1,553,044		
4.	Fuel, Gas	501.3			
5.	Fuel, Other	501.4			
6.	**Fuel SubTotal** (*2 thru 5*)	501	28,638,357	16.85	
7.	Steam Expenses	502	7,225,021		
8.	Electric Expenses	505	272,709		
9.	Miscellaneous Steam Power Expenses	506	5,362,538		
10.	Allowances	509			
11.	Rents	507			
12.	**Non-Fuel SubTotal** (*1 + 7 thru 11*)		13,554,850	7.98	
13.	**Operation Expense** (*6 + 12*)		42,193,207	24.83	
14.	Maintenance, Supervision and Engineering	510	949,109		
15.	Maintenance of Structures	511	326,691		
16.	Maintenance of Boiler Plant	512	9,411,342		
17.	Maintenance of Electric Plant	513	2,356,877		
18.	Maintenance of Miscellaneous Plant	514	301,304		
19.	**Maintenance Expense** (*14 thru 18*)		13,345,323	7.85	
20.	**Total Production Expense** (*13 + 19*)		55,538,530	32.68	
21.	Depreciation	403.1, 411.10	9,102,206		
22.	Interest	427	10,574,247		
23.	**Total Fixed Cost** (*21 + 22*)		19,676,453	11.58	
24.	**Power Cost** (*20 + 23*)		75,214,983	44.26	

Remarks

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART E - HYDRO PLANT**	BORROWER DESIGNATION
	PLANT
	PERIOD ENDED

INSTRUCTIONS - See help in the online application.

SECTION A. HYDRO GENERATING UNITS

NO.	UNIT NO. (*a*)	SIZE (kW) (*b*)	GROSS GENERATION (MWh) (*c*)	OPERATING HOURS IN SERVICE (*d*)	ON STANDBY (*e*)	OUT OF SERVICE SCHEDULED (*f*)	UNSCHEDULED (*g*)
1.							
2.							
3.							
4.							
5.							
6.	**Total**						

NO.	ITEM	VALUE	HYDRAULIC DATA ITEM	(*a*) MAXIMUM	(*b*) MINIMUM
7.	Station Service (MWh)				
8.	Net Generation (MWh)				
9.	Station Service % of Gross		1. Pool Elevation (ft.)		
10.	Energy for Pumped Storage (MWh)		2. Tail Race Elevation (ft.)		
11.	**Net Generation after Pumped Storage (MWh)**		Water Spilled ☐ Yes ☐ No		

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)		5.	Maintenance Plant Payroll ($)	
2.	No. Employees Part Time		6.	Other Accounts Plant Payroll ($)	
3.	**Total Employee Hours Worked**		7.	**Total Plant Payroll ($)**	
4.	Operating Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	
2.	Plant Factor (%)	
3.	Running Plant Capacity Factor (%)	
4.	15 Min. Gross Max. Demand (kW)	
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (*a*)	MILLS/NET kWh (*b*)
1.	Operation, Supervision and Engineering	535		
2.	Water for Power	536		
3.	Energy for Pumped Storage	536.1		
4.	Hydraulic Expense	537		
5.	Electric Expense	538		
6.	Miscellaneous Hydraulic Power Generation Expense	539		
7.	Rents	540		
8.	**Operation Expense (*1 thru 7*)**			
9.	Maintenance, Supervision and Engineering	541		
10.	Maintenance of Structures	542		
11.	Maintenance of Reservoirs, Dams and Waterways	543		
12.	Maintenance of Electric Plant	544		
13.	Maintenance of Miscellaneous Hydraulic Plant	545		
14.	**Maintenance Expense (*9 thru 13*)**			
15.	**Total Production Expense (*8 + 14*)**			
16.	Depreciation	403.3, 411.10		
17.	Interest	427		
18.	**Total Fixed Cost (*16 + 17*)**			
19.	**Power Cost (*15 + 18*)**			

Remarks (including Unscheduled Outages)

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

BORROWER DESIGNATION

PLANT

PERIOD ENDED

INSTRUCTIONS - See help in the online application.

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

			FUEL CONSUMPTION				OPERATING HOURS					
									OUT OF SERVICE			
NO.	UNIT NO. (*a*)	SIZE (kW) (*b*)	OIL (1000 Gals.) (*c*)	GAS (1000 C.F.) (*d*)	OTHER (e)	TOTAL (*f*)	IN SERVICE (*g*)	ON STANDBY (*h*)	SCHED. (*i*)	UNSCH. (*j*)	GROSS GENER.(MWh) (*k*)	BTU PER kWh (*l*)
1.												
2.												
3.												
4.												
5.												
6.	**Total**											
7.	Average BTU						Station Service (MWh)					
8.	Total BTU (10^6)						Net Generation (MWh)					
9.	Total Del. Cost ($)						Station Service % of Gross					

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1.	No. Employees Full Time (Include Superintendent)		5.	Maintenance Plant Payroll ($)	
2.	No. Employees Part Time		6.	Other Accounts Plant Payroll ($)	
3.	**Total Employee Hours Worked**		**7.**	**Total Plant Payroll ($)**	
4.	Operating Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	
2.	Plant Factor (%)	
3.	Running Plant Capacity Factor (%)	
4.	15 Min. Gross Max. Demand (kW)	
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (*a*)	MILLS/NET (kWh) (*b*)	$/10^6 BTU (*c*)
1.	Operation, Supervision and Engineering	546			
2.	Fuel, Oil	547.1			
3.	Fuel, Gas	547.2			
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel SubTotal** (*2 thru 5*)	547			
7.	Generation Expenses	548			
8.	Miscellaneous Other Power Generation Expenses	549			
9.	Rents	550			
10.	**Non-Fuel SubTotal** (*1 + 7 thru 9*)				
11.	**Operation Expense** (*6 + 10*)				
12.	Maintenance, Supervision and Engineering	551			
13.	Maintenance of Structures	552			
14.	Maintenance of Generating and Electric Plant	553			
15.	Maintenance of Miscellaneous Other Power Generating Plant	554			
16.	**Maintenance Expense** (*12 thru 15*)				
17.	**Total Production Expense** (*11 + 16*)				
18.	Depreciation	403.4, 411.10			
19.	Interest	427			
20.	**Total Fixed Cost** (*18 + 19*)				
21.	**Power Cost** (*17 + 20*)				

Remarks (including Unscheduled Outages)

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART F CC - COMBINED CYCLE PLANT**	BORROWER DESIGNATION
	PLANT
INSTRUCTIONS - See help in the online application.	PERIOD ENDED

SECTION A. COMBINED CYCLE GENERATING UNITS

NO.	UNIT NO. (*a*)	SIZE (kW) (*b*)	FUEL CONSUMPTION OIL (1000 Gals.) (*c*)	GAS (1000 CF) (*d*)	OTHER (*e*)	TOTAL (*f*)	OPERATING HOURS IN SERVICE (*g*)	ON STANDBY (*h*)	OUT OF SERVICE SCHED. (*i*)	UNSC. (*j*)	GROSS GENER. (MWh) (*k*)	BTU PER kWh (*l*)
1.												
2.												
3.												
4.												
5.												
6.	**Total**											
7.	Average BTU						Station Service (MWh)					
8.	Total BTU (10^6)						Net Generation (MWh)					
9.	Total Del. Cost ($)						Station Service % Of Gross					

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1.	No. Employees Full Time (Include. Superintendent)		5.	Maintenance Plant Payroll ($)	
2.	No. Employees Part Time		6.	Other Accounts Plant Payroll ($)	
3.	**Total Employee Hours Worked**		7.	**Total Plant Payroll ($)**	
4.	Operating Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	
2.	Plant Factor (%)	
3.	Running Plant Capacity Factor (%)	
4.	15 Min. Gross Max. Demand (kW)	
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (*a*)	MILLS/NET kWh (*b*)	$/10^6 BTU (*c*)
1.	Operation, Supervision and Engineering	500			
2.	Fuel, Oil	547.1			
3.	Fuel, Gas	547.2			
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel SubTotal** ***(2 thru 5)***	547			
7.	Generation Expenses	548			
8.	Miscellaneous Other Power Generation Expenses	549			
9.	Rents	507			
10.	Steam Expenses	502			
11.	Electric Expenses	505			
12.	Miscellaneous Steam Power Expenses	506			
13.	Allowances	509			
14.	**Non-Fuel SubTotal** ***(1 + 7 thru 13)***				
15.	**Operating Expense** ***(6 + 14)***				
16.	Maintenance, Supervision and Engineering	551, 510			
17.	Maintenance of Structures	552, 511			
18.	Maintenance of Generating and Electric Plant	553, 513			
19.	Maintenance of Miscellaneous Other Power Generating Plant	554, 514			
20.	**Maintenance Expense** ***(16 thru 19)***				
21.	**Total Production Expense** ***(15 + 20)***				
22.	Depreciation	403.4, 403.1, 411.10			
23.	Interest	427			
24.	**Total Fixed Cost** ***(22 + 23)***				
25.	**Power Cost** ***(21 + 24)***				

Remarks

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART G - NUCLEAR PLANT**	BORROWER DESIGNATION
	PLANT
INSTRUCTIONS - See help in the online application.	PERIOD ENDED

SECTION A. BOILERS AND GENERATING UNITS

NO.	UNIT NO. (*a*)	TIMES STARTED (*b*)	SIZE (kW) (*c*)	GROSS GENERATION (MWh) (*d*)	OPERATING HOURS: IN SERVICE (*e*)	OPERATING HOURS: ON STANDBY (*f*)	OUT OF SERVICE: SCHEDULED (*g*)	OUT OF SERVICE: UNSCHEDULED (*h*)
1.								
2.								
3.								
4.								
5.								
6.	**Total**							
7.	Station Service (MWh)							
8.	Net Generation (MWh)							
9.	Station Service % Of Gross							

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1.	No. Employees Full Time (Include. Superintendent)		5.	Maintenance Plant Payroll ($)	
2.	No. Employees Part Time		6.	Other Accounts Plant Payroll ($)	
3.	**Total Employee Hours Worked**		7.	**Total Plant Payroll ($)**	
4.	Operating Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	
2.	Plant Factor (%)	
3.	Running Plant Capacity Factor (%)	
4.	15 Min. Gross Max. Demand (kW)	
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (*a*)	MILLS/NET kWh (*b*)
1.	Operation, Supervision and Engineering	517		
2.	Fuel	518.1		
3.	Less Fuel Acquisition Adjustment	518.2		
4.	**Net Fuel Expense** (*2 - 3*)			
5.	Coolants and Water	519		
6.	Steam Expenses	520		
7.	Steam From Other Sources	521		
8.	Electric Expenses	523		
9.	Miscellaneous Nuclear Power Expense	524		
10.	Rents	525		
11.	**Operation Expense** (*1 + 4 thru 10*)			
12.	Maintenance, Supervision and Engineering	528		
13.	Maintenance of Structures	529		
14.	Maintenance of Reactor Plant Equipment	530		
15.	Maintenance of Electric Plant	531		
16.	Maintenance of Miscellaneous Nuclear Plant	532		
17.	**Maintenance Expense** (*12 thru 16*)			
18.	Reactor Credits			
19.	**Total Production Expense** (*11 + 17 - 18*)			
20.	Depreciation	403.2, 411.10		
21.	Interest	427		
22.	**Total Fixed Cost** (*20 + 21*)			
23.	Less Plant Acquisition Adjustment	406		
24.	**Power Cost (19 + 22 - 23)**			

Remarks (including Unscheduled Outages)

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART II - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020 PERIOD ENDED December, 2013
INSTRUCTIONS - See help in the online application.	

SECTION A. UTILITY PLANT

ITEM	BALANCE BEGINNING OF YEAR (*a*)	ADDITIONS (*b*)	RETIREMENTS (*c*)	ADJUSTMENTS AND TRANSFERS (*d*)	BALANCE END OF YEAR (*e*)
1. Total Intangible Plant (301 thru 303)	0				0
2. Total Steam Production Plant (*310 thru 317*)	347,134,574	12,849,964			359,984,538
3. Total Nuclear Production Plant (*320 thru 326*)	0				0
4. Total Hydro Production Plant (*330 thru 337*)	0				0
5. Total Other Production Plant (*340 thru 347*)	2,011,953				2,011,953
6. **Total Production Plant (*2 thru 5*)**	349,146,527	12,849,964			361,996,491
7. Land and Land Rights (*350*)	9,128,541	254,822			9,383,363
8. Structures and Improvements (*352*)	0				0
9. Station Equipment (*353*)	71,679,070	1,607,497	256,840		73,029,727
10. Other Transmission Plant (*354 thru 359.1*)	128,577,198	298,641	392,536		128,483,303
11. **Total Transmission Plant (*7 thru 10*)**	209,384,809	2,160,960	649,376		210,896,393
12. Land and Land Rights (*360*)	0				0
13. Structures and Improvements (*361*)	0				0
14. Station Equipment (*362*)	60,785,293	4,140,001	1,149,867		63,775,427
15. Other Distribution Plant (*363 thru 374*)	0				0
16. **Total Distribution Plant (*12 thru 15*)**	60,785,293	4,140,001	1,149,867		63,775,427
17. RTO/ISO Plant (380 thru 386)					
18. Total General Plant (*389 thru 399.1*)	44,912,292	2,969,217	1,389,578		46,491,931
19. **Electric Plant in Service (*1 + 6 + 11 + 16 thru 18*)**	664,228,921	22,120,142	3,188,821		683,160,242
20. Electric Plant Purchased or Sold (*102*)	0				0
21. Electric Plant Leased to Others (*104*)	0				0
22. Electric Plant Held for Future Use (*105*)	0				0
23. Completed Construction Not Classified (*106*)	0				0
24. Acquisition Adjustments (*114*)	0				0
25. Other Utility Plant (*118*)	0				0
26. Nuclear Fuel Assemblies (*120.1 thru 120.4*)	0				0
27. **Total Utility Plant in Service (*19 thru 26*)**	664,228,921	22,120,142	3,188,821		683,160,242
28. Construction Work in Progress (*107*)	146,949,478	168,497,100			315,446,578
29. **Total Utility Plant (*27 + 28*)**	811,178,399	190,617,242	3,188,821		998,606,820

SECTION B. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION - UTILITY PLANT

ITEM	COMP. RATE (%) (a)	BALANCE BEGINNING OF YEAR (*b*)	ANNUAL ACCRUALS (*c*)	RETIREMENTS LESS NET SALVAGE (*d*)	ADJUSTMENTS AND TRANSFERS (*e*)	BALANCE END OF YEAR (*f*)
1. Depr. of Steam Prod. Plant (108.1)		58,972,885	8,902,038			67,874,923
2. Depr. of Nuclear Prod. Plant (108.2)		0				0
3. Depr. of Hydraulic Prod. Plant (108.3)		0				0
4. Depr. of Other Prod. Plant (108.4)		1,038,751	100,598			1,139,349
5. Depr. of Transmission Plant (108.5)		64,316,945	4,398,102	33,564		68,681,483
6. Depr. of Distribution Plant (108.6)		16,986,926	943,564	126,268		17,804,222
7. Depr. of General Plant (108.7)		27,082,850	1,745,135	1,252,571		27,575,414
8. Retirement Work in Progress (108.8)		0				0
9. **Total Depr. for Elec. Plant in Serv. (*1 thru 8*)**		168,398,357				183,075,391
10. Depr. of Plant Leased to Others (109)		0				0
11. Depr. of Plant Held for Future Use (110)		0				0
12. Amort. of Elec. Plant in Service (111)		0				0
13. Amort. of Leased Plant (112)		0				0
14. Amort. of Plant Held for Future Use		0				0
15. Amort. of Acquisition Adj. (115)		0				0
16. Depr. & Amort. Other Plant (119)		0				0
17. Amort. of Nuclear Fuel (120.5)		0				0
18. **Total Prov. for Depr. & Amort. (*9 thru 17*)**		168,398,357	16,089,437	1,412,403		183,075,391

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART H - ANNUAL SUPPLEMENT

BORROWER DESIGNATION
ND0020

PERIOD ENDED
December, 2013

INSTRUCTIONS - See help in the online application.

SECTION B. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION - UTILITY PLANT (*Continued*)

19. Amount of Annual Accrual Charged to Expense $ 16,089,437	20. Amount of Annual Accrual Charged to Other Accounts $	21. Book Cost of Property Retired $ 3,188,821
22. Removal Cost of Property Retired $ 270,346	23. Salvage Material from Property Retired $ 2,046,764	24. Renewal and Replacement Cost $

SECTION C. NON-UTILITY PLANT

ITEM	BALANCE BEGINNING OF YEAR (*a*)	ADDITIONS (*b*)	RETIREMENTS (*c*)	ADJUSTMENTS AND TRANSFERS (*d*)	BALANCE END OF YEAR (*e*)
1. NonUtility Property (121)					
2. Provision For Depr. & Amort. (122)					

SECTION D. DEMAND AND ENERGY AT POWER SOURCES

MONTH	PEAK DEMAND (MW) (*a*)	MONTHLY PEAKS DATE (*b*)	TIME (*c*)	TYPE OF READING (*d*)	ENERGY OUTPUT (MWh) (*e*)
1. January	926	01/24/2013	12	Coincident	485,018
2. February	828	02/01/2013	13	Coincident	405,054
3. March	732	03/19/2013	7	Coincident	410,533
4. April	656	04/09/2013	7	Coincident	343,037
5. May	557	05/03/2013	8	Coincident	283,725
6. June	501	06/25/2013	19	Coincident	261,801
7. July	558	07/18/2013	18	Coincident	293,727
8. August	603	08/27/2013	18	Coincident	303,545
9. September	555	09/06/2013	17	Coincident	279,941
10. October	690	10/29/2013	8	Coincident	348,342
11. November	770	11/22/2013	7	Coincident	441,191
12. December	876	12/31/2013	14	Coincident	533,435
13. Annual Peak	926			**Annual Total**	4,389,349

SECTION E. DEMAND AND ENERGY AT DELIVERY POINTS

MONTH	DELIVERED TO RUS BORROWERS DEMAND (MW) (*a*)	ENERGY (MWh) (b)	DELIVERED TO OTHERS DEMAND (MW) (*c*)	ENERGY (MWh) (*d*)	TOTAL DELIVERED DEMAND (MW) (*e*)	ENERGY (MWh) (*f*)
1. January	642	397,516		68,374	642	465,890
2. February	748	396,548		110,837	748	507,385
3. March	676	317,852		166,088	676	483,940
4. April	600	312,191		227,907	600	540,098
5. May	490	241,560		219,784	490	461,344
6. June	394	218,078		104,647	394	322,725
7. July	461	236,812		206,296	461	443,108
8. August	462	228,953		256,260	462	485,213
9. September	502	258,694		126,838	502	385,532
10. October	457	243,379		112,376	457	355,755
11. November	633	351,284		51,496	633	402,780
12. December	741	580,522		122,621	741	703,143
13. Peak or Total	748	3,783,389		1,773,524	748	5,556,913

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020 PERIOD ENDED December, 2013

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an 'X' in column (e). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION I. INVESTMENTS

No	Description (a)	Included ($) (b)	Excluded ($) (c)	Income Or Loss ($) (d)	Rural Development (e)
2	**Investments in Associated Organizations**				
	Beltrami Electric Cooperative, Inc.	2,231			
	Cass County Electric Cooperative, Inc.	9,548			
	Cavalier Rural Electric Cooperative, Inc.	2,895			
	Clearwater-Polk Electric Cooperative, Inc.	2,112			
	Nodak Electric Cooperative, Inc.	19,234			
	North Star Electric Cooperative, Inc.	1,699			
	PKM Electric Cooperative, Inc.	1,885			
	Red Lake Electric Cooperative, Inc.	1,892			
	Red River Electric Cooperative, Inc.	2,366			
	Roseau Electric Cooperative, Inc.	3,376			
	Wild Rice Electric Cooperative, Inc.	1,573			
	Lignite Electric Cooperative, Inc.	100			
	Totals	48,911			
4	**Other Investments**				
	Capital Electric Cooperative	6,277			
	Cenex	8,617			
	CoBank	6,675,194			
	Dakota Valley	1,361			
	Dairyland Power Cooperative	10			
	Federated Rural Electric	150,482			
	Garden Valley Telephone	15,262			
	Lake States Forestry Coop	100			
	National Rural Utilities CFC	6,444			
	ND Small Business Investment Co	1,322			
	Northern Plains Electric	2,444			
	Paul Bunyon Rural Telephone	4,866			
	Polar Communication	2,962			
	Red River Rural Telephone	1,526			
	RESCO - Rural Electric Coop	42,072			
	Roughrider	8,068			
	Touchstone Energy	1,515			
	West River Mutual Aid Telephone	58			
	United Telephone Mutual Aid Corporation	37,483			
	Totals	6,966,063			
6	**Cash - General**				
	General Checking & Savings	176,673			
	Petty Cash	6,000			
	RUS Construction Fund	100			
	Land and Easement Fund	11,500			
	Totals	194,273			
8	**Temporary Investments**				
	Temporary Investments	1,252,428			
	Totals	1,252,428			
9	**Accounts and Notes Receivable - NET**				
	Accounts Receivable	10,871,555			

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020 PERIOD ENDED December, 2013

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an 'X' in column (e). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION I. INVESTMENTS

	Totals	10,871,555			
11	**TOTAL INVESTMENTS (1 thru 10)**	19,333,230			

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART II - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020 PERIOD ENDED December, 2013

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an 'X' in column (c). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION II. LOAN GUARANTEES

No	Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Rural Development (e)
	TOTAL				
	TOTAL (Included Loan Guarantees Only)				

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020 PERIOD ENDED December, 2013

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an "X" in column (e). Both "Included" and "Excluded" Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION III. RATIO

RATIO OF INVESTMENTS AND LOAN GUARANTEES TO UTILITY PLANT [Total of Included Investments (Sub Section I, 11b) and Loan Guarantees - Loan Balance (Sub Section II, 5d) to Total Utility Plant (Part A, Section B, Line 3 of this report)]	1.94 %

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION IV. LOAN

No	Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Rural Development (e)
	TOTAL				

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

SECTION G. MATERIALS AND SUPPLIES INVENTORY

ITEM	BALANCE BEGINNING OF YEAR (*a*)	PURCHASED & SALVAGED (*b*)	USED & SOLD (*c*)	BALANCE END OF YEAR (*d*)
1. Coal	3,646,240	26,868,672	27,183,825	3,331,087
2. Other Fuel	1,606,410	5,073,891	4,106,977	2,573,324
3. Production Plant Parts and Supplies	7,577,965	5,959,067	6,307,465	7,229,567
4. Station Transformers and Equipment	6,435,545	2,179,695	1,119,308	7,495,932
5. Line Materials and Supplies	2,065,406	716,512	428,459	2,353,459
6. Other Materials and Supplies	197,551	139,935	119,052	218,434
7. **Total (*1 thru 6*)**	21,529,117	40,937,772	39,265,086	23,201,803

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **OPERATING REPORT- ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020 PERIOD ENDED December, 2013
INSTRUCTIONS - See help in the online application.	This data will be used to review your financial situation. Your response is required (7 U.S.C. 901 et. seq.) and may be confidential

SECTION H. LONG-TERM DEBT AND DEBT SERVICE REQUIREMENTS

No	Item	Balance End Of Year (a)	Interest (Billed This Year) (b)	Principal (Billed This Year) (c)	Total (Billed This Year) (d)
1	RUS (Excludes RUS - Economic Development Loans)	3,170,523	172,219	437,782	610,001
2	National Rural Utilities Cooperative Finance Corporation				
3	CoBank, ACB	187,342,955	6,332,245	2,215,353	8,547,598
4	Federal Financing Bank	571,656,615	15,375,021	7,348,753	22,723,774
5	RUS - Economic Development Loans				
6	Payments Unapplied	40,000,000			
7	Principal Payments Received from Ultimate Recipients of IRP Loans				
8	Principal Payments Received from Ultimate Recipients of REDL Loans				
9	Principal Payments Received from Ultimate Recipients of EE Loans				
10	Accrued Pension	2,231,015			
	TOTAL	724,401,108	21,879,485	10,001,888	31,881,373

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

SECTION I. ANNUAL MEETING AND BOARD DATA

1. Date of Last Annual Meeting	2. Total Number of Members	3. Number of Members Present at Meeting	4. Was Quorum Present?
4/5/2013	31	14	Yes
5. Number of Members Voting by Proxy or Mail	**6. Total Number of Board Members**	**7. Total Amount of Fees and Expenses for Board Members**	**8. Does Manager Have Written Contract?**
0	12	$ 221,695	No

SECTION J. MAN-HOUR AND PAYROLL STATISTICS

1. Number of Full Time Employees	366	4. Payroll Expensed	30,372,294
2. Man-Hours Worked - Regular Time	770,750	5. Payroll Capitalized	4,399,662
3. Man-Hours Worked – Overtime	52,714	6. Payroll Other	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

SECTION K. LONG-TERM LEASES

No	Name Of Lessor (a)	Type Of Property (b)	Rental This Year (c)
1	Farm Credit Leasing	10 - 2 MWh Diesel Engines	315,031
	TOTAL		315,031

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION ND0020
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2013

SECTION L. RENEWABLE ENERGY CREDITS

ITEM	BALANCE BEGINNING OF YEAR *(a)*	ADDITIONS *(b)*	RETIREMENTS *(c)*	ADJUSTMENTS AND TRANSFER *(d)*	BALANCE END OF YEAR *(e)*
1. Renewable Energy Credits					

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART I - LINES AND STATIONS

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION: ND0020

PERIOD ENDED: December, 2013

SECTION A. EXPENSES AND COSTS

	ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
	Transmission Operation			
1.	Supervision and Engineering	560	382,156	
2.	Load Dispatching	561	5,031,567	
3.	Station Expenses	562		292,705
4.	Overhead Line Expenses	563	2,290,879	
5.	Underground Line Expenses	564		
6.	Miscellaneous Expenses	566	906,353	
7.	**Subtotal (*1 thru 6*)**		8,610,955	292,705
8.	Transmission of Electricity by Others	565	9,790,723	
9.	Rents	567	5,920	
10.	**Total Transmission Operation (*7 thru 9*)**		18,407,598	292,705
	Transmission Maintenance			
11.	Supervision and Engineering	568		
12.	Structures	569		
13.	Station Equipment	570		1,940,106
14.	Overhead Lines	571	3,408,143	
15.	Underground Lines	572		
16.	Miscellaneous Transmission Plant	573		
17.	**Total Transmission Maintenance (*11 thru 16*)**		3,408,143	1,940,106
18.	**Total Transmission Expense (*10 + 17*)**		21,815,741	2,232,811
19.	RTO/ISO Expense – Operation	575.1-575.8		
20.	RTO/ISO Expense – Maintenance	576.1-576.5		
21.	**Total RTO/ISO Expense (*19 + 20*)**			
22.	Distribution Expense - Operation	580-589		3,890,340
23.	Distribution Expense - Maintenance	590-598		1,983,108
24.	**Total Distribution Expense (*22 + 23*)**			5,873,448
25.	**Total Operation And Maintenance (*18 + 21 + 24*)**		21,815,741	8,106,259
	Fixed Costs			
26.	Depreciation – Transmission	403.5	2,642,589	1,755,513
27.	Depreciation – Distribution	403.6		943,564
28.	Interest – Transmission	427	2,258,859	1,521,272
29.	Interest – Distribution	427		829,785
30.	**Total Transmission (*18 + 26 + 28*)**		26,717,189	5,509,596
31.	**Total Distribution (*24 + 27 + 29*)**			7,646,797
32.	**Total Lines And Stations (*21 + 30 + 31*)**		26,717,189	13,156,393

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES			SUBSTATIONS	
	VOLTAGE (kV)	MILES	TYPE	CAPACITY(kVA)
1.	41 KV	29.13	13. Distribution Lines	
2.	69 KV	2,138.13		
3.	230 KV	443.87	**14. Total (*12 + 13*)**	3,090.16
4.	345 KV	214.33		
5.	115 KV	264.70	15. Stepup at Generating Plants	256,000
6.				
7.			16. Transmission	1,424,967
8.				
9.			17. Distribution	1,219,781
10.				
11.			**18. Total (*15 thru 17*)**	2,900,748
12.	**Total (*1 thru 11*)**	3,090.16		

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees: 114

ITEM	LINES	STATIONS
2. Oper. Labor	2,601,572	1,747,046
3. Maint. Labor	1,350,894	1,714,789
4. Oper. Material	64,980	30,594
5. Maint. Material	358,647	874,481

SECTION D. OUTAGES

1. Total	
2. Avg. No. of Distribution Consumers Served	
3. Avg. No. of Hours Out Per Consumer	

APPENDIX F

Minnesota Electric Utility Information

Reporting-Forecast Section

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE NAME OR ORDER OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:

Cells shown with a light green background correspond to headings for columns, rows or individual fields.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:

rule7610.reports@state.mn.us

If you have any questions please contact:

Steve Loomis
MN Department of Commerce
steve.loomis@state.mn.us
(651) 539-1690

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	69
REPORT YEAR	2013

RILS ID#	U12705

UTILITY DETAILS	
UTILITY NAME	Minnkota Power Coop
STREET ADDRESS	1822 Mill Road
CITY	Grand Forks
STATE	ND
ZIP CODE	58203
TELEPHONE	701/795-4315
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	Co-op

CONTACT INFORMATION	
CONTACT NAME	JAMIE OVERGAARD
CONTACT TITLE	RATES, LOAD AND PLANNING MANAGER
CONTACT STREET ADDRESS	1822 MILL ROAD
CITY	GRAND FORKS
STATE	ND
ZIP CODE	58203
TELEPHONE	701-795-4214
CONTACT E-MAIL	jovergaard@minnkota.com

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	JAMIE OVERGAARD
PREPARER'S TITLE	RATES, LOAD AND PLANNING MANAGER
DATE	6/12/2014

ALLOWABLE UTILITY TYPES

Code

Private

Public

Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2013	No. of Cust.	78,960	47,165	11,190	0	225	619	118	138,278	138,278
		MWH	1,478,137	773,481	1,023,868	0	745,448	9,738	189,796	4,220,468	4,220,468
Present Year	2014	No. of Cust.	79,930	47,622	11,397	0	229	632	118	139,929	139,929
		MWH	1,384,596	735,644	807,869	0	940,347	9,871	187,670	4,065,997	4,065,997
1st Forecast Year	2015	No. of Cust.	81,004	48,166	11,550	0	233	643	118	141,714	141,714
		MWH	1,394,852	741,009	821,593	0	962,741	10,021	189,587	4,119,803	4,119,803
2nd Forecast Year	2016	No. of Cust.	82,366	48,835	11,754	0	241	654	119	143,968	143,968
		MWH	1,410,055	748,504	837,079	0	999,856	10,171	190,008	4,195,674	4,195,674
3rd Forecast Year	2017	No. of Cust.	83,724	49,500	11,959	0	245	666	119	146,213	146,213
		MWH	1,431,304	758,559	852,944	0	1,022,702	10,338	190,432	4,266,279	4,266,279
4th Forecast Year	2018	No. of Cust.	85,033	50,141	12,160	0	251	678	120	148,383	148,383
		MWH	1,455,862	770,004	869,131	0	1,049,485	10,504	190,857	4,345,844	4,345,844
5th Forecast Year	2019	No. of Cust.	86,302	50,763	12,360	0	254	690	120	150,490	150,490
		MWH	1,475,301	779,221	885,100	0	1,066,206	10,670	190,285	4,406,783	4,406,783
6th Forecast Year	2020	No. of Cust.	87,526	51,366	12,559	0	260	702	121	152,533	152,533
		MWH	1,496,755	789,302	901,280	0	1,084,865	10,834	189,716	4,472,753	4,472,753
7th Forecast Year	2021	No. of Cust.	88,719	51,955	12,757	0	263	714	121	154,529	154,529
		MWH	1,522,187	801,080	919,125	0	1,091,462	10,998	189,152	4,534,003	4,534,003
8th Forecast Year	2022	No. of Cust.	89,868	52,523	12,951	0	269	727	122	156,461	156,461
		MWH	1,549,616	813,697	937,910	0	1,104,996	11,178	188,589	4,605,986	4,605,986
9th Forecast Year	2023	No. of Cust.	90,979	53,073	13,144	0	273	740	122	158,332	158,332
		MWH	1,574,740	825,304	957,101	0	1,117,468	11,357	188,028	4,673,999	4,673,999
10th Forecast Year	2024	No. of Cust.	92,056	53,609	13,335	0	277	753	123	160,153	160,153
		MWH	1,599,541	836,778	975,451	0	1,127,876	11,536	187,472	4,738,653	4,738,653
11th Forecast Year	2025	No. of Cust.	93,102	54,131	13,524	0	280	766	123	161,925	161,925
		MWH	1,623,071	847,696	993,770	0	1,134,222	11,713	186,919	4,797,390	4,797,390
12th Forecast Year	2026	No. of Cust.	94,116	54,640	13,712	0	285	779	124	163,656	163,656
		MWH	1,642,413	856,832	1,010,909	0	1,151,505	11,889	186,370	4,859,918	4,859,918
13th Forecast Year	2027	No. of Cust.	95,103	55,137	13,897	0	288	793	124	165,343	165,343
		MWH	1,658,413	864,528	1,027,256	0	1,157,725	12,082	185,825	4,905,829	4,905,829
14th Forecast Year	2028	No. of Cust.	96,060	55,622	14,082	0	292	807	125	166,987	166,987
		MWH	1,673,409	871,806	1,043,324	0	1,167,881	12,274	185,284	4,953,979	4,953,979

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2013	No. of Cust.	41,480	28,732	6,530	0	65	166	71	77,044	77,044
		MWH	754,787	438,927	478,915	0	141,121	1,385	86,268	1,901,403	1,901,403
Present Year	2014	No. of Cust.	41,619	28,843	6,608	0	66	170	66	77,372	77,372
		MWH	698,330	424,235	427,583	0	126,902	1,415	89,764	1,768,230	1,768,230
1st Forecast Year	2015	No. of Cust.	41,589	28,901	6,627	0	67	172	66	77,423	77,423
		MWH	698,313	425,112	431,551	0	130,372	1,423	92,127	1,778,898	1,778,898
2nd Forecast Year	2016	No. of Cust.	41,880	29,098	6,698	0	69	174	67	77,985	77,985
		MWH	701,756	427,480	435,504	0	135,847	1,430	92,991	1,795,008	1,795,008
3rd Forecast Year	2017	No. of Cust.	42,204	29,306	6,769	0	69	176	67	78,590	78,590
		MWH	709,827	431,800	439,680	0	137,326	1,438	93,855	1,813,925	1,813,925
4th Forecast Year	2018	No. of Cust.	42,506	29,501	6,839	0	70	178	67	79,162	79,162
		MWH	719,598	436,817	444,036	0	138,811	1,445	94,718	1,835,425	1,835,425
5th Forecast Year	2019	No. of Cust.	42,793	29,688	6,909	0	70	180	68	79,708	79,708
		MWH	727,050	440,805	448,321	0	139,301	1,452	94,581	1,851,511	1,851,511
6th Forecast Year	2020	No. of Cust.	43,060	29,866	6,979	0	71	182	68	80,227	80,227
		MWH	733,811	444,497	452,489	0	141,797	1,459	94,446	1,868,499	1,868,499
7th Forecast Year	2021	No. of Cust.	43,322	30,042	7,050	0	71	184	68	80,737	80,737
		MWH	745,336	450,219	456,965	0	142,298	1,466	94,312	1,890,595	1,890,595
8th Forecast Year	2022	No. of Cust.	43,564	30,207	7,120	0	73	186	69	81,218	81,218
		MWH	758,958	456,821	461,447	0	145,804	1,473	94,177	1,918,680	1,918,680
9th Forecast Year	2023	No. of Cust.	43,793	30,364	7,188	0	73	188	69	81,675	81,675
		MWH	770,182	462,372	465,848	0	146,316	1,480	94,043	1,940,241	1,940,241
10th Forecast Year	2024	No. of Cust.	44,013	30,517	7,257	0	73	190	70	82,120	82,120
		MWH	781,763	468,080	470,187	0	146,833	1,487	93,910	1,962,259	1,962,259
11th Forecast Year	2025	No. of Cust.	44,227	30,667	7,326	0	73	192	70	82,554	82,554
		MWH	792,564	473,440	474,439	0	147,356	1,493	93,778	1,983,070	1,983,070
12th Forecast Year	2026	No. of Cust.	44,434	30,815	7,395	0	74	194	70	82,982	82,982
		MWH	801,011	477,802	478,576	0	148,885	1,500	93,648	2,001,421	2,001,421
13th Forecast Year	2027	No. of Cust.	44,638	30,961	7,464	0	74	196	71	83,404	83,404
		MWH	806,738	480,991	482,556	0	149,420	1,506	93,520	2,014,731	2,014,731
14th Forecast Year	2028	No. of Cust.	44,836	31,105	7,534	0	74	198	71	83,818	83,818
		MWH	811,612	483,821	486,514	0	149,961	1,512	93,393	2,026,812	2,026,812

* MINING needs to be reported as a separate category only if annual sales are greatere than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2013	1,901,403	2,319,065	1,210,901	1,528,033	4,937,285	399,685	2,521,730	1,698,738	0
Present Year	2014	1,768,230	2,297,767	850,000	2,360,595	5,983,000	406,408	2,439,598	1,626,399	0
1st Forecast Year	2015	1,778,898	2,340,904	800,000	3,428,507	7,160,000	411,690	2,482,181	1,637,622	0
2nd Forecast Year	2016	1,795,008	2,400,666	750,000	3,295,254	7,160,000	419,072	2,538,383	1,657,291	0
3rd Forecast Year	2017	1,813,925	2,452,354	700,000	3,167,578	7,160,000	426,143	2,591,765	1,674,515	0
4th Forecast Year	2018	1,835,425	2,510,419	650,000	3,029,967	7,160,000	434,189	2,650,965	1,694,879	0
5th Forecast Year	2019	1,851,511	2,555,271	600,000	2,913,059	7,160,000	440,159	2,699,154	1,707,628	0
6th Forecast Year	2020	1,868,499	2,604,254	550,000	2,790,610	7,160,000	446,637	2,750,743	1,722,010	0
7th Forecast Year	2021	1,890,595	2,643,408	500,000	2,673,070	7,160,000	452,927	2,799,747	1,734,256	0
8th Forecast Year	2022	1,918,680	2,687,306	450,000	2,543,545	7,160,000	460,469	2,855,711	1,750,275	0
9th Forecast Year	2023	1,940,241	2,733,758	400,000	2,418,687	7,160,000	467,314	2,909,564	1,764,434	0
10th Forecast Year	2024	1,962,259	2,776,394	350,000	2,297,415	7,160,000	473,932	2,961,658	1,776,995	0
11th Forecast Year	2025	1,983,070	2,814,319	300,000	2,182,676	7,160,000	479,935	3,010,362	1,787,028	0
12th Forecast Year	2026	2,001,421	2,858,496	250,000	2,063,895	7,160,000	486,188	3,061,748	1,798,169	0
13th Forecast Year	2027	2,014,731	2,891,098	150,000	1,913,444	7,160,000	490,727	3,102,937	1,802,892	0
14th Forecast Year	2028	2,026,812	2,927,167	100,000	1,810,569	7,160,000	495,452	3,145,777	1,808,202	0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

		FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day	2013	404	225	187	0	104	2	38	960	960.0

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year	2013	960.0	862.0	762.0	683.0	586.0	528.0	589.0	634.0	586.0	721.0	798.0	909.0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MW)

NAME OF OTHER UTILITY =>			WAPA (MPC)	WAPA (NMPA)						
Past Year	2013	Summer	44	31						
		Winter	72	34						
Present Year	2014	Summer	44	31						
		Winter	72	34						
1st Forecast Year	2015	Summer	44	31						
		Winter	72	34						
2nd Forecast Year	2016	Summer	44	31						
		Winter	72	34						
3rd Forecast Year	2017	Summer	44	31						
		Winter	72	34						
4th Forecast Year	2018	Summer	44	31						
		Winter	72	34						
5th Forecast Year	2019	Summer	44	31						
		Winter	72	34						
6th Forecast Year	2020	Summer	44	31						
		Winter	72	34						
7th Forecast Year	2021	Summer	44	31						
		Winter	72	34						
8th Forecast Year	2022	Summer	44	31						
		Winter	72	34						
9th Forecast Year	2023	Summer	44	31						
		Winter	72	34						
10th Forecast Year	2024	Summer	44	31						
		Winter	72	34						
11th Forecast Year	2025	Summer	44	31						
		Winter	72	34						
12th Forecast Year	2026	Summer	44	31						
		Winter	72	34						
13th Forecast Year	2027	Summer	44	31						
		Winter	72	34						
14th Forecast Year	2028	Summer	44	31						
		Winter	72	34						

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2: FIRM SALES (Express in MW)

NAME OF OTHER UTILITY =>			MP							
Past Year	2013	Summer	0							
		Winter	0							
Present Year	2014	Summer	50							
		Winter	150							
1st Forecast Year	2015	Summer	150							
		Winter	150							
2nd Forecast Year	2016	Summer	150							
		Winter	150							
3rd Forecast Year	2017	Summer	100							
		Winter	150							
4th Forecast Year	2018	Summer	100							
		Winter	100							
5th Forecast Year	2019	Summer	100							
		Winter	100							
6th Forecast Year	2020	Summer	100							
		Winter	100							
7th Forecast Year	2021	Summer	100							
		Winter	80							
8th Forecast Year	2022	Summer	80							
		Winter	60							
9th Forecast Year	2023	Summer	60							
		Winter	40							
10th Forecast Year	2024	Summer	40							
		Winter	20							
11th Forecast Year	2025	Summer	20							
		Winter	0							
12th Forecast Year	2026	Summer	0							
		Winter	0							
13th Forecast Year	2027	Summer	0							
		Winter	0							
14th Forecast Year	2028	Summer	0							
		Winter	0							

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MW)

NAME OF OTHER UTILITY =>			NMPA							
Past Year	2013	Summer	14							
		Winter	14							
Present Year	2014	Summer	14							
		Winter	14							
1st Forecast Year	2015	Summer	14							
		Winter	14							
2nd Forecast Year	2016	Summer	14							
		Winter	14							
3rd Forecast Year	2017	Summer	14							
		Winter	14							
4th Forecast Year	2018	Summer	14							
		Winter	14							
5th Forecast Year	2019	Summer	14							
		Winter	14							
6th Forecast Year	2020	Summer	14							
		Winter	14							
7th Forecast Year	2021	Summer	14							
		Winter	14							
8th Forecast Year	2022	Summer	14							
		Winter	14							
9th Forecast Year	2023	Summer	14							
		Winter	14							
10th Forecast Year	2024	Summer	14							
		Winter	14							
11th Forecast Year	2025	Summer	14							
		Winter	14							
12th Forecast Year	2026	Summer	14							
		Winter	14							
13th Forecast Year	2027	Summer	14							
		Winter	14							
14th Forecast Year	2028	Summer	14							
		Winter	14							

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MW)

NAME OF OTHER UTILITY =>			NSP	BEPC						
Past Year	2013	Summer	100	0						
		Winter	0	50						
Present Year	2014	Summer	100	50						
		Winter	0	50						
1st Forecast Year	2015	Summer	100	50						
		Winter	0	50						
2nd Forecast Year	2016	Summer	0	200						
		Winter	0	0						
3rd Forecast Year	2017	Summer	0	200						
		Winter	0	0						
4th Forecast Year	2018	Summer	0	200						
		Winter	0	0						
5th Forecast Year	2019	Summer	0	0						
		Winter	0	0						
6th Forecast Year	2020	Summer	0	0						
		Winter	0	0						
7th Forecast Year	2021	Summer	0	0						
		Winter	0	0						
8th Forecast Year	2022	Summer	0	0						
		Winter	0	0						
9th Forecast Year	2023	Summer	0	0						
		Winter	0	0						
10th Forecast Year	2024	Summer	0	0						
		Winter	0	0						
11th Forecast Year	2025	Summer	0	0						
		Winter	0	0						
12th Forecast Year	2026	Summer	0	0						
		Winter	0	0						
13th Forecast Year	2027	Summer	0	0						
		Winter	0	0						
14th Forecast Year	2028	Summer	0	0						
		Winter	0	0						

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2013	Summer	634	86	554	554	75	0	479	479	779	64	100	743	63	542	201
		Winter	960	365	595	595	106	0	489	489	779	14	50	743	73	562	181
Present Year	2014	Summer	582	88	494	595	75	50	469	570	1006	14	150	870	97	566	304
		Winter	950	370	580	580	106	150	624	624	1006	14	50	970	79	703	267
1st Forecast Year	2015	Summer	589	90	499	580	75	150	574	655	1006	14	150	870	94	668	202
		Winter	960	375	585	585	106	150	629	629	1006	14	50	970	94	723	247
2nd Forecast Year	2016	Summer	599	92	507	585	75	150	582	660	1006	14	200	820	88	670	150
		Winter	974	380	594	594	106	150	638	638	1006	14	0	1020	96	734	286
3rd Forecast Year	2017	Summer	608	94	514	594	75	100	539	619	1006	14	200	820	90	629	191
		Winter	988	385	603	603	106	100	597	597	1006	14	0	1020	90	687	333
4th Forecast Year	2018	Summer	619	96	523	603	75	100	548	628	1006	14	200	820	91	639	181
		Winter	1004	390	614	614	106	100	608	608	1006	14	0	1020	91	699	321
5th Forecast Year	2019	Summer	627	98	529	614	75	100	554	639	1006	14	0	1020	92	646	374
		Winter	1015	395	620	620	106	100	614	614	1006	14	0	1020	92	706	314
6th Forecast Year	2020	Summer	636	100	536	620	75	100	561	645	1006	14	0	1020	93	654	366
		Winter	1028	400	628	628	106	100	622	622	1006	14	0	1020	93	715	305
7th Forecast Year	2021	Summer	644	102	542	628	75	100	567	653	1006	14	0	1020	94	661	359
		Winter	1040	405	635	635	106	80	609	609	1006	14	0	1020	94	703	317
8th Forecast Year	2022	Summer	653	104	549	635	75	80	554	640	1006	14	0	1020	93	647	373
		Winter	1055	410	645	645	106	60	599	599	1006	14	0	1020	93	692	328
9th Forecast Year	2023	Summer	662	106	556	645	75	60	541	630	1006	14	0	1020	91	632	388
		Winter	1068	415	653	653	106	40	587	587	1006	14	0	1020	91	678	342
10th Forecast Year	2024	Summer	671	108	563	653	75	40	528	618	1006	14	0	1020	89	617	403
		Winter	1081	420	661	661	106	20	575	575	1006	14	0	1020	89	664	356
11th Forecast Year	2025	Summer	678	110	568	661	75	20	513	606	1006	14	0	1020	87	600	420
		Winter	1093	425	668	668	106	0	562	562	1006	14	0	1020	87	649	371
12th Forecast Year	2026	Summer	687	112	575	668	75	0	500	593	1006	14	0	1020	85	585	435
		Winter	1105	430	675	675	106	0	569	569	1006	14	0	1020	85	654	366
13th Forecast Year	2027	Summer	693	114	579	675	75	0	504	600	1006	14	0	1020	86	590	430
		Winter	1114	435	679	679	106	0	573	573	1006	14	0	1020	86	659	361
14th Forecast Year	2028	Summer	699	116	583	679	75	0	508	604	1006	14	0	1020	86	594	426
		Winter	1123	440	683	683	106	0	577	577	1006	14	0	1020	87	664	356

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MW)

		ADDITIONS	RETIREMENTS
Past Year	2013		
Present Year	2014		
1st Forecast Year	2015		
2nd Forecast Year	2016		
3rd Forecast Year	2017		
4th Forecast Year	2018		
5th Forecast Year	2019		
6th Forecast Year	2020		
7th Forecast Year	2021		
8th Forecast Year	2022		
9th Forecast Year	2023		
10th Forecast Year	2024		
11th Forecast Year	2025		
12th Forecast Year	2026		
13th Forecast Year	2027		
14th Forecast Year	2028		

COMMENTS
There are no retirements to report.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of the worksheet.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	LIG	Name of Fuel	WIND	Name of Fuel		Name of Fuel		Name of Fuel		Name of Fuel	
		Unit of Measure	TONS	Unit of Measure		Unit of Measure		Unit of Measure		Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2013	3,164,215	3,766,362		1,165,852								
Present Year	2014	3,850,965	4,670,273		1,313,474								
1st Forecast Year	2015	4,811,240	5,846,834		1,313,475								
2nd Forecast Year	2016	4,811,240	5,846,834		1,313,475								
3rd Forecast Year	2017	4,811,240	5,846,834		1,313,475								
4th Forecast Year	2018	4,811,240	5,846,834		1,313,475								
5th Forecast Year	2019	4,811,240	5,846,834		1,313,475								
6th Forecast Year	2020	4,811,240	5,846,834		1,313,475								
7th Forecast Year	2021	4,811,240	5,846,834		1,313,475								
8th Forecast Year	2022	4,811,240	5,846,834		1,313,475								
9th Forecast Year	2023	4,811,240	5,846,834		1,313,475								
10th Forecast Year	2024	4,811,240	5,846,834		1,313,475								
11th Forecast Year	2025	4,811,240	5,846,834		1,313,475								
12th Forecast Year	2026	4,811,240	5,846,834		1,313,475								
13th Forecast Year	2027	4,811,240	5,846,834		1,313,475								
14th Forecast Year	2028	4,811,240	5,846,834		1,313,475								

LIST OF FUEL TYPES

BIT - Bituminous Coal	LPG - Liquefied Propane Gas	HYD - Hydro (water)
COAL - Coal (general)	NG - Natural Gas	WIND - Wind
DIESEL - Diesel	NUC - Nuclear	WOOD - Wood
FO2 - Fuel Oil #2 (Mid-distillate)	REF - Refuse, Bagasse, Peat, Non-wc	SOLAR - Solar
FO6 - Fuel Oil #6 (Residual fuel oil)	STM - Steam	
LIG - Lignite	SUB - Sub-bituminous coal	

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	**To Be Built** (enter X for selection)	**To Be Retired** (enter X for selection)	**DESIGN VOLTAGE**	**SIZE OF CONDUCTOR**	**TYPE OF CONDUCTOR**	**D.C. OR A.C. (specify)**	**LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS**	**INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"**	**LENGTH IN MINNESOTA (miles)**

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest

	DATE	DATE	
			<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	357	850	
0200	341	840	
0300	333	837	
0400	328	857	
0500	333	840	
0600	354	602	
0700	392	599	
0800	433	608	
0900	463	583	
1000	490	648	
1100	518	911	
1200	539	960	
1300	557	917	
1400	578	885	
1500	**590**	861	
1600	605	856	
1700	622	861	
1800	634	**707**	
1900	633	648	
2000	602	609	
2100	580	585	
2200	579	750	
2300	526	935	
2400	459	882	

COMMENTS