Minnkota Power COOPERATIVE

A Touchstone Energy® Cooperative

June 28, 2019

Dr. Daniel P. Wolf
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 2019 Resource Plan; ET6/RP-19-416.

Dear Dr. Wolf,

Minnkota Power Cooperative, Inc., a Minnesota cooperative corporation, respectfully files this 2019 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. ET6-RP-14-526.

This Resource Plan covers the forecast period of 2019 – 2033, 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 Resource 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.
5301 32nd Ave S
Grand Forks, ND 58201

C: Service List

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	**Chair**
Dan Lipschultz	**Vice Chair**
John Tuma	**Commissioner**
Matthew Schuerger	**Commissioner**
Valerie Means	**Commissioner**

In the Matter of the 2019 Resource Plan of Minnkota Power Cooperative, Inc. — *Docket No. 19-416*

AFFIDAVIT OF SERVICE

STATE OF NORTH DAKOTA)
)ss.
COUNTY OF GRAND FORKS)

Samuel Schmitz, being first duly sworn on oath, deposes and states:

That on the 28th day of June, 2019, he served copies of the Minnkota Power Cooperative, Inc. 2019 Resource Plan, in the above-referenced matter, upon the parties on the attached service list by e-filing.

Samuel Schmitz
Minnkota Power Cooperative, Inc.
5301 32nd Avenue S
Grand Forks, ND 58201
701-795-4000

Subscribed and sworn to before me this 28th day of June, 2019.

Notary Public

KIMBERLY JOHNSON RUSTAD
Notary Public
State of North Dakota
My Commission Expires Oct. 9, 2022

Minnkota Power Cooperative, Inc.

– and –

Northern Municipal Power Agency

2019 INTEGRATED RESOURCE PLAN

2019 – 2033

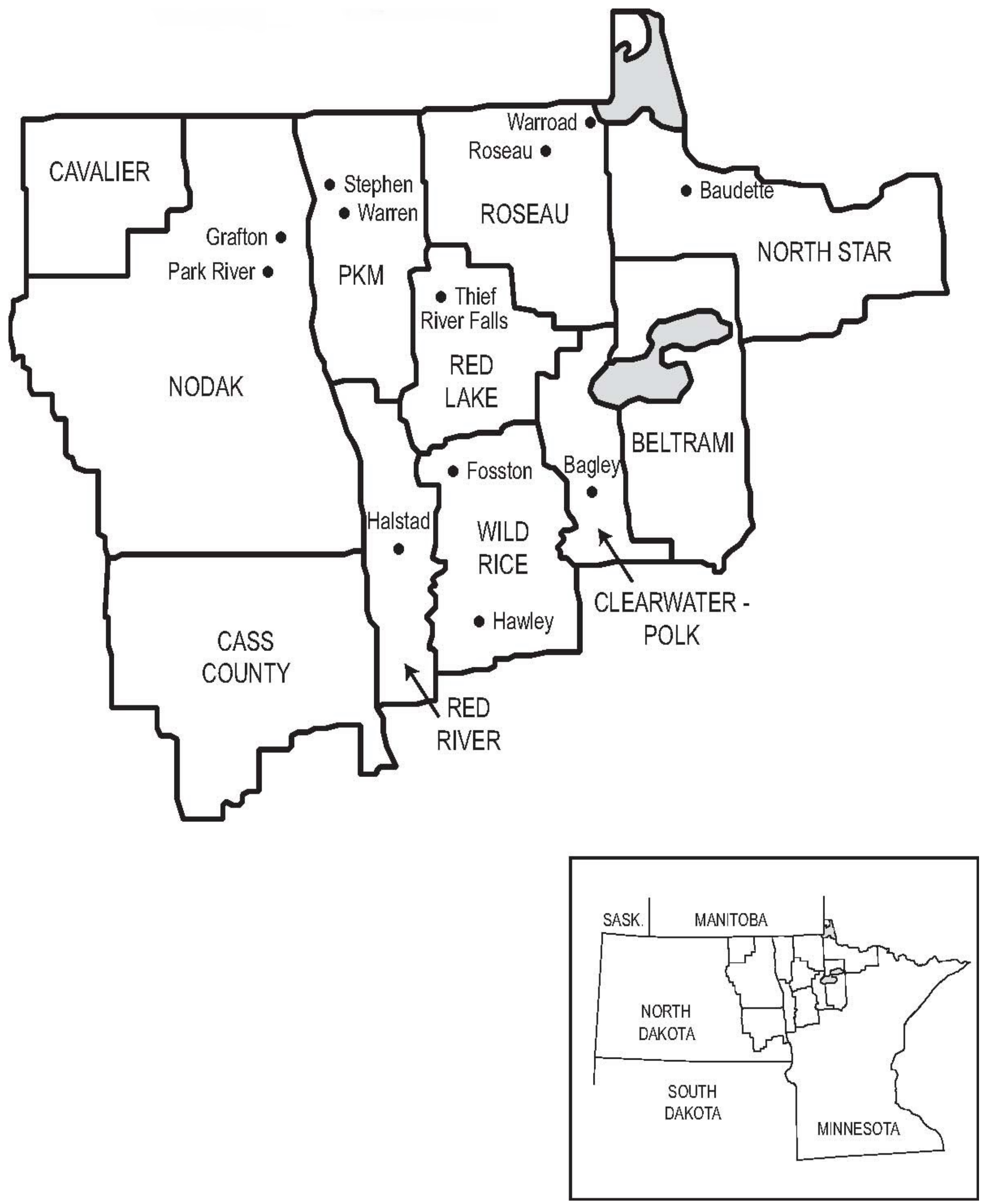
Submitted to the

Western Area Power Administration

– and the –

Minnesota Public Utilities Commission

SERVICE AREA



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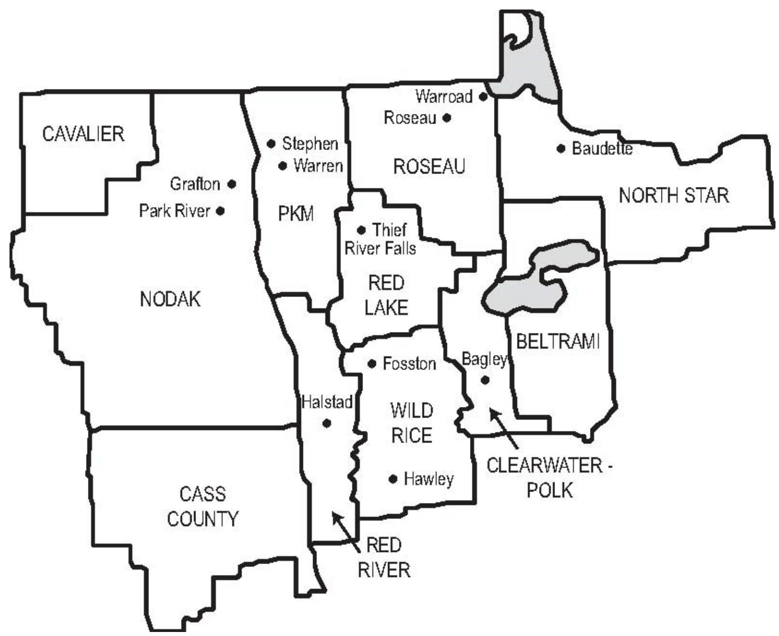
SECTION 1
Introduction

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 330,000 people. The member systems serve approximately 137,000 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 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, providing certain conditions are met.

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 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 of Mortgage, dated as of June 14, 2012, 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 a delegate meeting. 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 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 15,300 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 as a liaison.

NMPA owns a 30% share of the Coyote generating plant, a 427 MW facility located near Beulah, N.D. NMPA also owns an undivided interest in Minnkota's transmission system based on a ratio of NMPA's load to the Joint System load. 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 consistent with applicable tax law relative to NMPA's tax-exempt financing. 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 390 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 210 employees operate out of the general headquarters in Grand Forks, N.D. Approximately 180 are employed at the Milton R. Young Station located near Center, N.D.

1.8 Market Participant - Midcontinent Independent System Operator's Energy Market (MISO)

Minnkota is a market participant in the 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

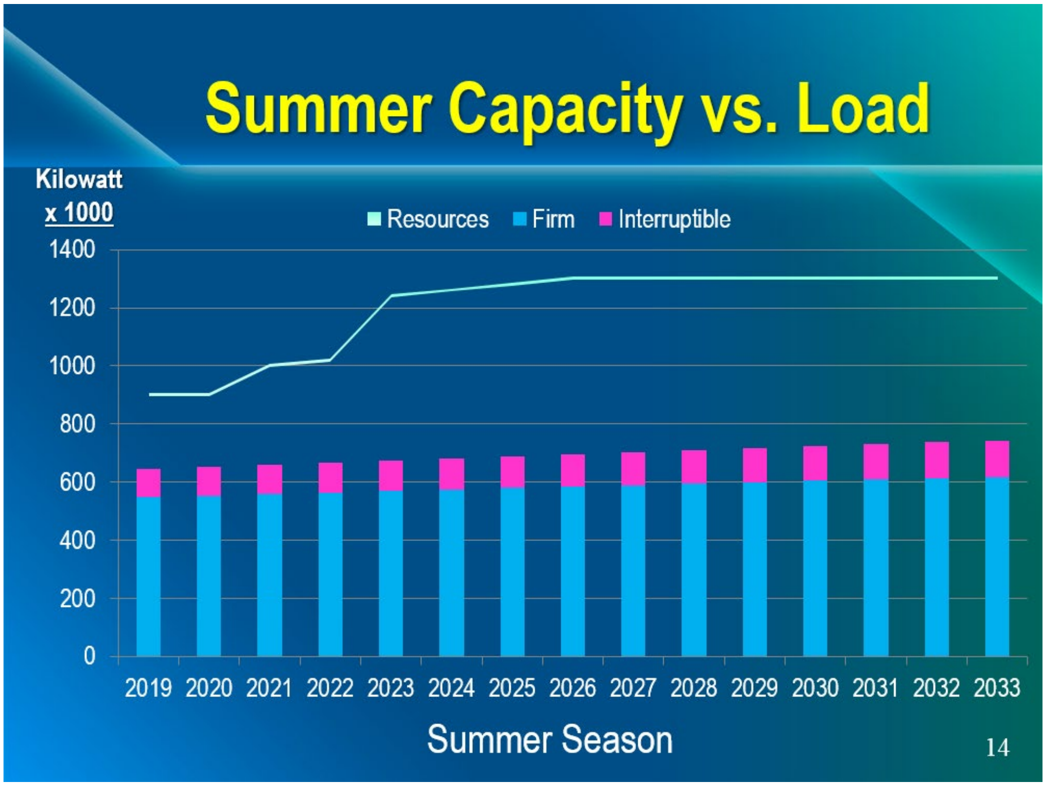
2.1 Introduction

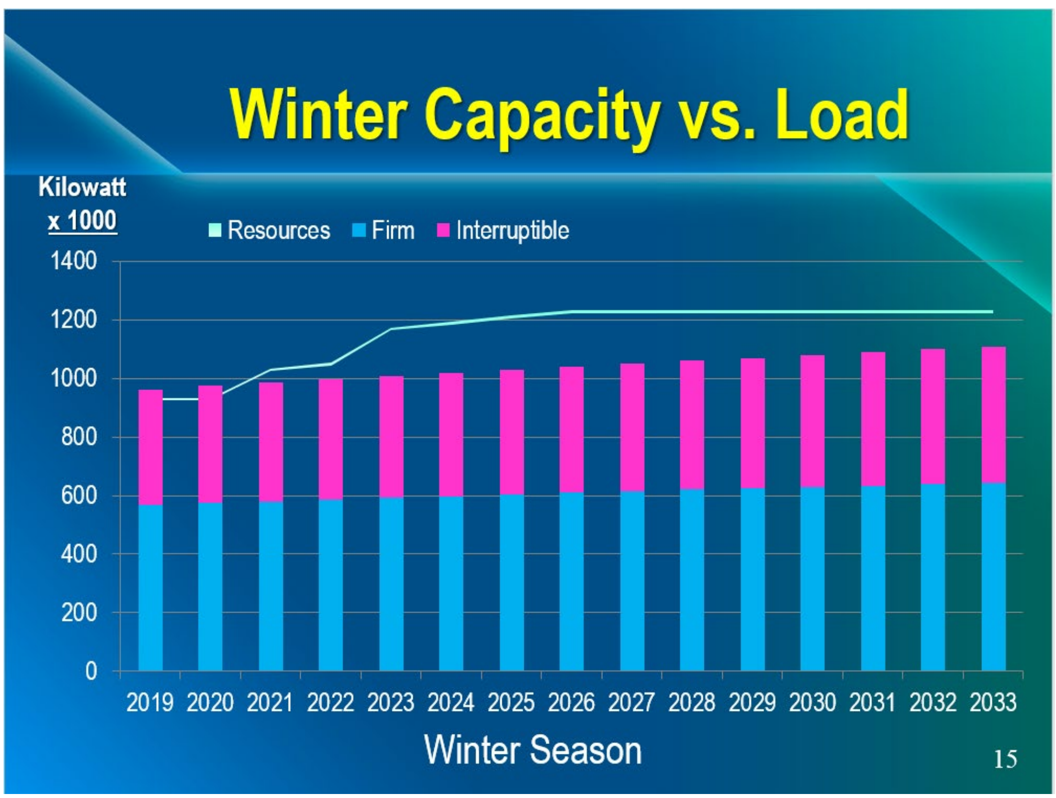
Minnkota and NMPA together submit this 2019 Integrated Resource Plan (IRP). This document has been prepared to fulfill the IRP requirements of WAPA and the Minnesota Public Utilities Commission.

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 and technological impacts.

2.2 Load Forecasts

The Joint System energy requirements are forecasted to increase at a rate of 1.0% per year. The summer and winter peak demands are also forecasted to increase at a rate of .8% and 1.0% respectively per year. This is based on the 30-year projections from the 2017 Load Forecast 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. 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 diverse energy resources as detailed in Section 4. 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 power purchase 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 power purchase agreements, it is forecasted that the Joint System purchases from the MISO energy market will range from a low of 0.3% to a high of 2.4% 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 2019-2033 timeframe.

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

The Joint System's 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 and the Joint System.

The Joint System has 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, electric transportation, and miscellaneous loads.

In the mid-1990s, the Joint System extended its DR program to include the summer season. This was done to offset increasing costs caused 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, electric transportation and miscellaneous loads.

Winter and Summer interruptible load forecasts

Winter Season	Interruptible Load - MW
2019	395
2020	400
2021	405
2022	410
2023	415
2024	420
2025	425
2026	430
2027	435
2028	440
2029	445
2030	450
2031	455
2032	460
2033	465

Summer Season	Interruptible Load - MW
2019	98
2020	100
2021	102
2022	104
2023	106
2024	108
2025	110
2026	112
2027	114
2028	116
2029	118
2030	120
2031	122
2032	124
2033	126

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

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 (owned by Square Butte) 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

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 1.62 MW General Electric machines with a total capacity of 171.7 MW. OTP owns 43.74 MW and NextEra owns 127.98 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 repower 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

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 Oliver III Wind

The Oliver III Wind Project consists of 43 GE 2.10 MW wind turbine generators and 5 GE 1.79 MW wind turbine generators owned by NextEra, with a total capacity of 99.3 MW, in Morton County and Oliver County, North Dakota. Minnkota has a long-term power purchase agreement with NextEra for the output of 99.3 MW of capacity and energy.

4.2.7 Infinity Wind

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.

4.2.8 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.

4.2.9 Cass County Electric Cooperative Diesel Generation

Minnkota leases 10 diesel generating units for Cass County Electric Cooperative. These generators are located at several substations and are the financial responsibility of Cass County. Minnkota purchases the capacity and energy from these units. 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.

4.2.10 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 358,303 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 40.6 winter / 36.2 summer and 174,311 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.

4.4 Sales

4.4.1 Basin Electric Power Cooperative Sales

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

2019 Annual	100 MW	March - November
2020 Annual	100 MW	March - November
2021 Annual	100 MW	March - November
2022 Annual	100 MW	March - May

4.4.2 Minnesota Power Sales

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

2019	Annual	50 MW
2020	Annual	50 MW

4.5 Transmission Facilities

Minnkota's transmission facilities consist of 464 miles of 345 kV, 444 miles of 230 kV, 284 miles of 115 kV and 2,158 miles of line up to and including 69 kV. Additionally, Minnkota completed 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 seventh 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 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 practical, 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

Econometric 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. 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 2017.

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 1999 through 2016 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
2019	4,920,659	941	616
2020	4,972,154	948	622
2021	5,018,491	955	627
2022	5,067,216	962	632
2023	5,115,885	969	638
2024	5,165,298	975	643
2025	5,213,228	982	649
2026	5,272,247	990	655
2027	5,323,772	997	661
2028	5,373,923	1,003	666
2029	5,426,486	1,010	672
2030	5,484,133	1,018	678
2031	5,534,124	1,024	684
2032	5,595,833	1,033	690
2033	5,648,466	1,039	696

The Joint System's median forecast of annual energy requirements is projected to increase a rate of 1.0% 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 0.8% per year. These numbers are based on the 30 year projections from the 2017 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
2019	4,735,279	866	568
2020	4,772,037	879	575
2021	4,825,376	886	582
2022	4,882,365	895	588
2023	4,930,061	903	594
2024	4,973,373	911	599
2025	5,020,187	918	604
2026	5,064,970	925	608
2027	5,081,734	928	611
2028	5,095,287	933	615
2029	5,113,999	936	618
2030	5,144,310	939	621
2031	5,172,603	944	626
2032	5,216,477	950	631
2033	5,256,383	956	636

The Joint System's low load growth scenario forecasts an increase of 0.85% per year for annual energy requirements. The winter peak demand is forecasted increase at a rate of 0.45% per year and the summer peak demand is forecasted to increase at a rate of 0.45% 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
2019	5,086,455	962	632
2020	5,142,451	976	641
2021	5,216,679	984	648
2022	5,295,292	995	655
2023	5,364,245	1,005	661
2024	5,428,803	1,014	667
2025	5,497,555	1,022	673
2026	5,564,463	1,031	678
2027	5,630,138	1,039	685
2028	5,692,938	1,050	692
2029	5,762,211	1,058	699
2030	5,845,428	1,067	707
2031	5,927,329	1,078	716
2032	6,028,204	1,091	725
2033	6,125,736	1,103	735

The Joint System's high load growth scenario forecasts an increase of 1.8% per year for annual energy requirements. The winter peak demand is forecasted to increase at a rate of 1.3% per year and the summer peak demand is forecasted to increase at a rate of 1.2% per year.

SECTION 6
Resource Adequacy

6.1 Discussion

The Joint System is a load serving entity within the MISO area of operations. As such, the Joint System 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 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, Ashtabula and Oliver III 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. (LFS Table 4.1)

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
2019	4,563,382	5,257,351	5,257,351
2020	4,585,832	5,339,759	5,339,759
2021	4,602,902	5,417,818	5,417,818
2022	4,621,918	5,499,290	5,499,290
2023	4,640,509	5,581,642	5,581,642
2024	4,662,385	5,662,467	5,662,467
2025	4,682,873	5,742,269	5,742,269

2026	4,713,031	5,835,021	5,835,021
2027	4,736,497	5,920,021	5,920,021
2028	4,760,869	6,001,733	6,001,733
2029	4,787,700	6,086,096	6,086,096
2030	4,818,649	6,177,157	6,177,157
2031	4,843,251	6,259,595	6,259,595
2032	4,877,046	6,356,935	6,356,935
2033	4,903,404	6,443,838	6,443,838

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
2019	91,268	98,413	105,147
2020	45,858	49,722	53,398
2021	46,029	50,185	54,178
2022	92,438	101,344	109,986
2023	46,405	51,159	55,816
2024	46,624	51,653	56,625
2025	46,829	52,132	57,423
2026	47,130	52,722	58,350
2027	47,365	53,238	59,200
2028	47,609	53,739	60,017
2029	47,877	54,265	60,861
2030	48,186	54,841	61,772
2031	48,433	55,341	62,596
2032	48,770	55,958	63,569
2033	49,034	56,485	64,438

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.

7.3 Long-Term Resource Needs

The Joint System's generation resources, power purchase agreements and extensive demand response program will meet the forecasts for peak demand and energy requirements. The Joint System is expected to have adequate resources to meet the capacity and energy requirements of its members/customers and will have a minimal dependence on the MISO energy market. Therefore, there is no need for future generation additions and no need for additional power purchase agreements in the next 15-year timeframe. Even with adequate resources Minnkota continues to evaluate new opportunities with our neighboring utilities as well as the development of new technologies.

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. 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., Ashtabula, N.D. and Oliver III 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. From the Oliver III wind project, Minnkota has rights to the output of 48 wind turbines with a nameplate capacity of 100 MW.

Between the Langdon, Ashtabula and Oliver III wind projects, Minnkota has rights to the output of 286 wind turbines with a nameplate capacity of 459 MW. For study purposes it was assumed that the annual capacity factor would be Langdon and Ashtabula – 42% and Oliver III – 50%, which translates into approximately 1,751,500 MWh of wind energy for the Joint System.

The following table documents the Joint System's Minnesota RES 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 wind energy forecasted to be generated by the portions of the Langdon and Ashtabula wind projects for which Minnkota has power purchase agreements. (MPC Req Summary 2019 Table 3.17 / Summary 3)

Year	Joint System Minnesota Retail Sales MWH	% Required For MN RES	Energy Requirement For MN RES MWH	Langdon, Ashtabula and Oliver III Wind Energy Production MWH
2019	1,890,017	17	321,303	1,751,500
2020	1,908,538	20	381,708	1,751, 500
2021	1,932,419	20	386,484	1,751, 500
2022	1,963,070	20	392,614	1,751,500
2023	1,986,643	20	397,329	1,751, 500
2024	2,010,661	20	402,132	1,751, 500
2025	2,033,234	25	508,309	1,751,500
2026	2,053,306	25	513,326	1,751, 500
2027	2,067,536	25	516,884	1,751,500
2028	2,080,540	25	520,135	1,751, 500
2029	2,093,282	25	523,320	1,751, 500
2030	2,107,670	25	526,917	1,751,500
2031	2,119,969	25	529,992	1,751, 500
2032	2,134,801	25	533,700	1,751, 500
2033	2,148,038	25	537,010	1,751,500

From the above tables it can be seen that the Joint System purchases from renewable energy resources are significantly greater than its requirements.

These tables demonstrate the Joint System's strong dedication to fulfilling its Minnesota RES requirements.

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.

The table below shows the estimated savings PowerSavers has had in the following respective years:

- 2014 - 27,209,892 kWh
- 2015 - 27,678,829 kWh
- 2016 - 31,584,595 kWh
- 2017 - 27,628,406 kWh
- 2018 - 21,538,490 kWh

The Joint System has met the MN energy efficiency and conservation requirements in all of the years it has participated in the CIP program and will continue to meet the requirements in the future.

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 has compiled ideas and resources under the PowerSavers name and logo.

The group organized under the name PowerSavers, which originally included 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® Appliances.

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 LEDs, 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 LEDs, low-flow faucet aerators, showerheads, pre-rinse sprayer valves, water heater temperature turndown and LED exit light retrofits.

Legislation was passed in May 2017 which removed the CIP requirements for cooperatives with fewer than 5,000 members and municipals with fewer than 1,000 consumers. This reduced the participating cooperatives and municipals to the following; Beltrami Electric Cooperative, North Star Electric Cooperative, Roseau Electric Cooperative, Wild Rice Electric Cooperative, Bagley Public Utilities, Baudette Municipal Utilities, Fosston Municipal Utilities, Hawley Municipal Utilities, Roseau Municipal Utilities, Thief River Municipal Utilities and Warren Municipal Utilities.

SECTION 10
Region Transmission Operator (RTO) Participation

10.1 Discussion

Minnkota occasionally performs studies to analyze RTO membership. Minnkota has strong transmission connections to Southwest Power Pool (SPP) and MISO, making them the logical options. Minnkota is presently a MISO market participant, which allows the purchase or sale of energy with the MISO energy market.

To date, the studies have shown that it is not in Minnkota's best interest to join an RTO, and Minnkota therefore does not presently have plans to do so.

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 MISO and Minnesota Transmission Owners (MTO).

11.2.1 MISO Transmission Planning

Through a Planning Coordinator (PC) services agreement, MISO has responsibility to conduct regional transmission planning for MPC and others in its PC footprint 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, generation interconnections, and economic analysis, all with transparency through stakeholder input. In addition, MISO coordinates with neighboring PCs, such as Southwest Power Pool (SPP).

Transmission owners that are members of MISO are responsible for developing their own system-specific transmission plans with help from MISO, which are then consolidated by MISO into an integrated overall MISO Transmission Expansion Plan. MISO Planning staff incorporates the plans submitted by the individual MISO transmission owners and sub-regional planning groups with stakeholder input and includes generation interconnection requests to develop a regional integrated plan for the orderly and cost-effective expansion of the MISO transmission system.

11.2.2 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.

SECTION 12
Environmental Compliance

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. Both units have a full suite of environmental controls, including controls for sulfur dioxide, nitrogen oxides, particulate, and mercury. Minnkota's target is always to be 100% compliant with all environmental regulations and is committed to environmental stewardship.

12.2 Coal Combustion Residuals (CCR)

The final rule dealing with the disposal of coal combustion residuals in landfills and surface impoundments was published in the Federal Register on April 17, 2015. The rule became effective on October 19, 2015, and Minnkota has been in full compliance since that date.

The rule sets requirements for both existing and newly constructed impoundments/landfills regarding location restrictions, structural integrity, operating criteria, groundwater protection, monitoring/reporting, and closure/post-closure.

Due to our pre-existing strong environmental CCR disposal practices, as well as proactive implementation of additional CCR disposal measures during the rulemaking process, we believe Minnkota to be in a very good place regarding the CCR rule and its potential future impacts.

Minnkota is currently permitted by the North Dakota Department of Environmental Quality (NDDEQ) for on-site CCR disposal at the MRYS facility through October 2025, at which point a renewal will be completed. We do not anticipate any significant challenges in continuing compliance with the CCR rule.

12.3 Waters of the United States (WOTUS)

The long-standing definition of federally jurisdictional WOTUS, under the Clean Water Act (CWA), was updated in a final rule issued in May 2015. The rule significantly expanded the jurisdiction of the federal government to include four new categories – tributaries, adjacent waters and wetlands, certain regional features, and waters within the 100-year floodplain – and retained the four previously defined categories – traditional navigable waters, interstate waters, territorial seas, and impoundment of any of these.

As written, the 2015 definition of WOTUS could have had a tremendous negative impact on Minnkota and like utilities, by increasing costs associated with construction and maintenance of transmission and distribution infrastructure, plant construction, operation, maintenance and decommissioning.

North Dakota was among a group of 28 states in which the 2015 WOTUS rule was stayed. As a result of Executive Order 13778, EPA and the Army Corps have since reviewed the 2015 WOTUS rule and proposed to rescind it and replace it with a new WOTUS definition that was published in February 2019.

Minnkota's first review of the 2019 proposal concludes that it is generally consistent with the pre-2015 definition of WOTUS, and we are generally supportive of the proposal as written. Minnkota will continue to follow the rulemaking process closely.

12.4 Steam Electric Effluent Limitation Guidelines (ELG)

The final ELG rule was published in November 2015 and provides regulatory standards for wastewater discharged to surface waters and municipal sewage treatment plants. There are six categories of wastewater that are regulated for units of >50 MW:

1. Flue gas desulfurization (FGD) scrubber wastewater
2. Fly ash transport water
3. Bottom ash transport water
4. Flue gas mercury control wastewater
5. Gasification wastewater
6. Combustion residual leachate

MRYS already has in place closed-loop (i.e., they are water consumers with no discharges) water systems that will limit the impact of this rule. For instance, while many plants around the country have FGD wastewater discharge (category one), MRYS recirculates water between the FGD scrubber and the CCR ponds. Therefore, there is no discharge of FGD water to surface waters.

Fly ash is dry handled, so category two is not applicable.

Concerning category three, bottom ash transport water, the current ELG language could impose a requirement of "zero liquid discharge" at the MRYS, which would require a modification to current operations. This restriction is being reviewed by EPA and final determination is pending. We are also evaluating potential options in the event that the current language is maintained.

Category four is not applicable at MRYS because all flue gas mercury controls (powdered activated carbon (PAC) injection) are dry handled with the fly ash.

MRYS is not a gasification plant, and thus category five is not applicable.

Leachate (category 6) from previously closed CCR impoundments is currently pumped to the active CCR ponds, and thus there is no surface water discharge.

As a result of litigation, the EPA is currently reconsidering the rule. We anticipate the rulemaking process to be complete in 2020. MRYS' North Dakota Pollutant Discharge Elimination System (NDPDES) permit will be expiring in June of 2020, and based on discussion with NDDEQ, we anticipate that ELG compliance will be required by December 2023.

Unless there are significant unexpected changes during EPA's reconsideration of the rule, we do not anticipate any major challenges in complying with the ELG rule once finalized.

12.5 Regional Haze

In July 2005, the EPA finalized the Regional Haze Regulations (RHR) and Guidelines for BART (Best Available Retrofit Technology) Determinations. Based on the RHR as well as a 2006 Consent Decree (CD) between Minnkota/Square Butte, the United States (on behalf of EPA), and the State of North Dakota, requirements for the MRYS emissions reductions for nitrogen oxides (NOx) and sulfur dioxide (SO_2) were laid out. Minnkota installed or implemented the following emissions controls on both Unit 1 and 2 at MRYS at a total cost of about $425 Million in the 2010-2011 timeframe:

- NOx control – separated over fire air (SOFA) plus selective non-catalytic reduction (SNCR) on both units
- SO_2 control – installation of a new wet flue gas desulfurization scrubber (WFGD) on Unit 1 and upgrade of the existing Unit 2 WFGD

Subsequently to the initial phase of the Regional Haze program, in July of 2016, EPA issued draft guidance for the second implementation period of the RHR. State Implementation Plans (SIP) are due in 2021. At the request of the NDDEQ and per the EPA 2016 guidance, Minnkota, in January 2019, submitted a Four-Factor Analysis to evaluate the cost, as well as other factors, for installation of additional NOx and SO_2 controls at the MRYS.

The Four-Factor Analysis concludes that the following emissions controls systems are technically feasible and have reasonable costs (as defined by NDDEQ-provided guidance) for installation at MRYS:

- NOx control – no change; continue operation of the existing SOFA + SNCR systems that achieve about 60% NOx reduction
- SO_2 control – modification/upgrade of both Unit 1 and 2 WFGDs to increase SO_2 removal efficiency to 97.4% on Unit 1 and 97.7% on Unit 2. Current removal mandates are set at 95% on Unit 1 and 90% (or 0.15 lb/10^6 Btu) on Unit 2. If required for installation as part of the RHR, these modifications would result in

combined annual SO_2 emissions reductions of about 1,250 tons based on baseline average annual emissions from 2016-2018.

Following submission of the Four-Factor Analysis, the NDDEQ and the Western Regional Air Partnership (WRAP) will be performing a series of visibility models to identify the progress in reducing visibility impairment in North Dakota's Class 1 areas. Once the visibility modeling is complete, NDDEQ will determine if additional controls will be required for the second implementation period. Minnkota is currently waiting on the results of the modeling efforts.

In the event that controls are required at MRYS for the second implementation period of the RHR, Minnkota anticipates that only those controls outlined in the Four-Factor Analysis as technically feasible and with reasonable costs would be required – modification of the existing SO_2 control systems. We do not currently expect this possibility to present a significant challenge in continuing to supply our member-owners with low-cost and reliable electricity.

Minnkota will continue to remain actively involved with the regulatory agencies during the second implementation period of the RHR.

12.6 Mercury & Air Toxics (MATS)

EPA promulgated the final Utility MATS rule in February 2012. The MATS rule targets emissions reductions of heavy metals, including mercury, arsenic, chromium and nickel; and acid gases such as hydrochloric and hydrofluoric acids. These are also known as hazardous air pollutants (HAPs) or air toxics. For lignite-fired electric generating units (EGUs), such as the MRYS, the primary standard of importance is for mercury, which was set at 4.0 lb/TBtu (trillion Btu) and represents an approximate 55-60% reduction at MRYS.

Based on the MATS rule, Minnkota has installed mercury control equipment at MRYS that includes proprietary coal additives and PAC injection systems on both units. The MATS rule became effective in 2015, and MRYS has maintained compliance since that date.

Recently, in December 2018, EPA issued a proposal to revise the Supplemental Cost Finding for mercury and air toxics that weighs the cost of controls implementation against the economic benefits attributable to regulating HAPs. The revised finding proposes that regulating mercury and other air toxics is not "appropriate and necessary." However, EPA states that the final MATS standards will remain in effect. In the same proposal, EPA also performed a "risk and technology review" and found that modifications to the emissions standards are not needed at this time.

Therefore, MRYS will maintain and continue to operate its mercury control systems to ensure compliance with the 4 lb/TBtu limit. We do not anticipate any significant challenges regarding mercury or other HAPs going forward.

12.7 Carbon Dioxide Regulations

The Clean Power Plan (CPP) final rule was published under section 111(d) of the Clean Air Act in October 2015. The CPP was a phased program (building blocks) that targeted a nationwide CO_2 reduction of 30% by 2030. The building blocks are summarized below:

1. Energy efficiency projects for coal-fired power plants to reduce heat rate
2. Increasing natural gas-fired generation and decreasing coal-fired generation
3. Increasing zero-emitting generation (i.e., renewables) and decreasing fossil-fired generation

Several states, including North Dakota and Minnesota, were more severely regulated than others; North Dakota was mandated a 45% emissions reduction and Minnesota a 40% reduction (both on a lb/MWh rate basis). Extensive litigation ensued, and ultimately the CPP was stayed by the U.S. Supreme Court in February 2016.

Had Minnkota been forced to comply with the CPP as written, there were likely to be significant consequences for the Co-op, our member owners and their consumers. One or both units of the MRYS may have been decommissioned or forced into significantly reduced load, resulting in the need to purchase more expensive/volatile power on the open market and/or replace the coal-fired generation with new generation (i.e., new wind or new natural gas generation). In any scenario based on the CPP, Minnkota's wholesale electricity rates would have been excessively increased. Ultimately, compliance with the CPP may have had a severe impact on our ability to continue providing low-cost and reliable power to our member owners.

Subsequently, the President Trump EPA has finalized a new rule – the Affordable Clean Energy (ACE) rule – that replaces the CPP under 111(d). The ACE rule, formally proposed on August 31, 2018 and finalized on June 19, 2019, overall represents a less severe approach to regulating CO_2 from existing EGUs. The key components of the ACE rule are summarized below:

- An "inside the fenceline" approach to identify the Best System of Emissions Reduction (BSER) at each affected facility; this is contrary to the statewide average approach adopted in the CPP.
- BSER was identified to be heat rate improvements; seven "candidate technologies" were listed along with estimated costs and heat rate impacts, which are to be used by States to determine emissions standards achievable at each source when considering unique factors for each source.
- The proposed rule included an update to the New Source Review (NSR) permitting program to incentivize the types of heat rate improvement projects that the ACE rule requires; the current NSR program has effectively served as a barrier for EGUs to undertake these types of projects in the past. The final rule,

however, does not include the proposed NSR reform, which EPA states will be addressed in a future rule making.

- ACE gives significant latitude to the States to set the emission reduction standards for each affected facility within their boundaries, a significant departure from the CPP approach.

In general, Minnkota supports EPA's ACE rule and strongly supports replacement of the CPP. Although the timing of the ACE rule finalization has given insufficient time to fully review the rule prior to submission of this IRP, the below generally summarizes the ACE implementation requirements as we currently understand them.

1. States will have three years from the date of the final rule publication to prepare and submit a SIP that establishes a standard of CO_2 emissions reductions performance:
    i. Each affected facility will determine which "candidate technologies" can be applied to each of their sources
    ii. The State must establish a standard of performance that reflects the emission limitation achievable at each affected source
    iii. The State must take into account at each affected source, factors that are unique to that source, such as technology and practices already implemented, remaining useful life of the plant, etcetera.
2. Once the SIP is submitted, EPA will have 18 months to review and approve or disapprove the SIP. If needed, EPA will have two years to develop a Federal Implementation Plan (FIP).
3. Compliance with the determined emissions limitation standards will be required within two years of submittal of the SIP, but there is some discretion given to the States to extend this compliance schedule based on source-specific factors.

As a part of the investigation into potential compliance with the CPP, Minnkota previously evaluated several heat rate improvement projects that could be implemented at MRYS. However, pending whether or not NSR reform is finalized in a future rulemaking (and in what ways) and the timing of such a rulemaking as it relates to the ACE compliance schedule, some of these projects may or may not be possible. Even with that uncertainty, we believe that we are well prepared to comply with the requirements of ACE without unreasonably affecting our member owners and their consumers.

12.8 Project Tundra

Despite the more relaxed requirements of the ACE rule, as compared to the CPP, Minnkota recognizes that there still exists the potential for future more stringent CO_2 regulations from existing coal-fired EGUs. We also recognize that despite carbon capture, utilization and storage (CCUS) technology not being adequately demonstrated to assume its nationwide viability, that the MRYS facility is situated in a unique geographical location. MRYS is located in close proximity to both geologic CO_2 storage sites (i.e., deep saline aquifers) as well as conventional oilfields that are capable of accepting CO_2 for enhanced oil recovery (EOR). This is not the case for many (or most) EGUs, and thus MRYS is in a unique situation where CCUS may be commercially viable.

Minnkota is spearheading the feasibility review of Project Tundra, a project to capture CO_2 emissions from the largest lignite unit in our resources. Modeled after the successful Petra Nova initiative in Texas, the vision for Project Tundra is to retrofit Unit 2 at MRYS with technology that could capture up to 95% of its CO_2 emissions. The CO_2 would then be sequestered in permanent geologic storage and/or utilized for EOR in the conventional oil fields of North Dakota. The project builds upon prior federal investment in Petra Nova by scaling up the application to process more flue gas, and apply to a cold weather climate, while utilizing lignite coal (Petra Nova uses flue gas from a subbituminous coal). The ultimate goal is to create a new benchmark – a large-scale demonstration at an existing plant that can be commercially and economically replicated across the region, the country, and the world.

Minnkota recognizes that carbon regulations present a longer-term risk to maintaining affordable and reliable resources that emit CO_2. If constructed, Project Tundra could help provide continued reliability and affordability of electricity from the power plant, while also preserving prior plant infrastructure investment. Using a technology-driven solution can help to reduce risk to our member-owners given the uncertainty of future CO_2 regulations.

Project Tundra has received important bi-partisan support, and has partnered with federal and State of North Dakota partners to advance its research and development. The project is presently conducting a feasibility review of key design considerations, including advanced amine solvents, economic modeling and aerosol mitigation and management. The project team is presently pursuing funding (significant leveraging of federal and State R&D funding) for the next phase, which is a front-end engineering design (approx. $30 million).

The overall cost of the project is estimated to be between $1.3-$1.6 billion with associated EOR infrastructure (if applicable). Minnkota is currently seeking outside investment in the project, entities that can harness applicable tax credits for carbon capture projects, so that the financial risk to Minnkota members can be limited.

Ultimately, Project Tundra can result in ~300 MW net of near "zero carbon" power for sale to our members with limited or no increase in cost, while still enabling continued use of North Dakota's abundant, reliable and low-cost lignite coal resources as well as ensuring the capital investment in MRYS can continue to be utilized. More details of Project Tundra can be found at www.projecttundrand.com

SECTION 13
Two-Year Action Plan

The Joint System will take the following actions during the 2019 to 2020 time frame as part of its ongoing efforts in Integrated Resource Planning:

A Load Forecast Study (LFS) will be completed for the Joint System in the fall of 2019. The LFS will track the growth in the demand and energy requirements of the Joint System.

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.

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 2021-2023 time frame as part of its ongoing efforts in Integrated Resource Planning:

A Load Forecast Study will be completed for the Joint System in 2021 and 2023. 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, the Joint System would most likely arrange the purchase of short-term generation capacity to serve the new load. The purchase would allow 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.

15.3 Resource Options Available in the Event of Facilities Shutdown

The Joint System would have a limited number of resource options available in the event that it was forced to shut down its lignite generation facilities. The Joint System currently has no surplus generation resources standing idle and ready to be placed into service other than costly standby diesel generators. In our view, the Joint System'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 the Joint System'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 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 Joint System's coal-fired generation were shut down, the financial impact on the Joint System's, and consequently the end-use customer, would be disastrous. The Joint System and their members/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 (SO_2), nitrous oxide (NO_X), particulate matter 10 microns and less (PM-10) and volatile organic compounds (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, the Joint System 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 currently has 459MW installed wind nameplate capacity to serve the energy needs for Minnesota and North Dakota members/customers. As long as the state of North Dakota does not impose a renewable energy requirement, a 50% or 75% renewable requirement would not require additional new renewable resources. However, a 50% or 75% renewable requirement in Minnesota without a renewable requirement in North Dakota, would force the Joint System to develop separate Minnesota and North Dakota wholesale power rates. This would lead to a significantly higher rate and cost to the Minnesota cooperative and municipal system end-use members/customers.

Any resource option requiring either 50% or 75% renewable resources will be significantly more costly than the base case option because of the intermittence of renewable resources. Backup generation such as a new natural gas turbine will be needed to serve firm load when renewable resources are not producing 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	May 29, 2019	Bemidji, MN
Cass County Electric Cooperative	May 28, 2019	Kindred, ND
Cavalier Rural Electric Cooperative	April 24, 2019	Langdon, ND
Clearwater-Polk Electric Cooperative	April 30, 2019	Bagley, MN
Nodak Electric Cooperative	May 7, 2019	Grand Forks, ND
North Star Electric Cooperative	April 3, 2019	Grand Forks, ND
PKM Electric Cooperative	May 28, 2019	Warren, MN
Red Lake Electric Cooperative	April 23, 2019	Red Lake Falls, MN
Red River Valley Cooperative Power Assoc.	May 22, 2019	Halstad, MN
Roseau Electric Cooperative	May 24, 2019	Roseau, MN
Wild Rice Electric Cooperative	May 28, 2019	Mahnomen, MN
Northern Municipal Power Agency	May 1, 2019	Thief River Falls, MN
Minnkota Power Cooperative, Inc.	May 30, 2019	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 H.

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 459 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. Minnkota and NMPA believe that 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.	See 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 2014 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 2017. 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**

20.3 Cross Reference to 2014 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 2019 and 2021. 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	2017

Number of Power Plants	4

UTILITY DETAILS

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

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	7/1/2018

COMMENTS

ALLOWABLE UTILITY TYPES

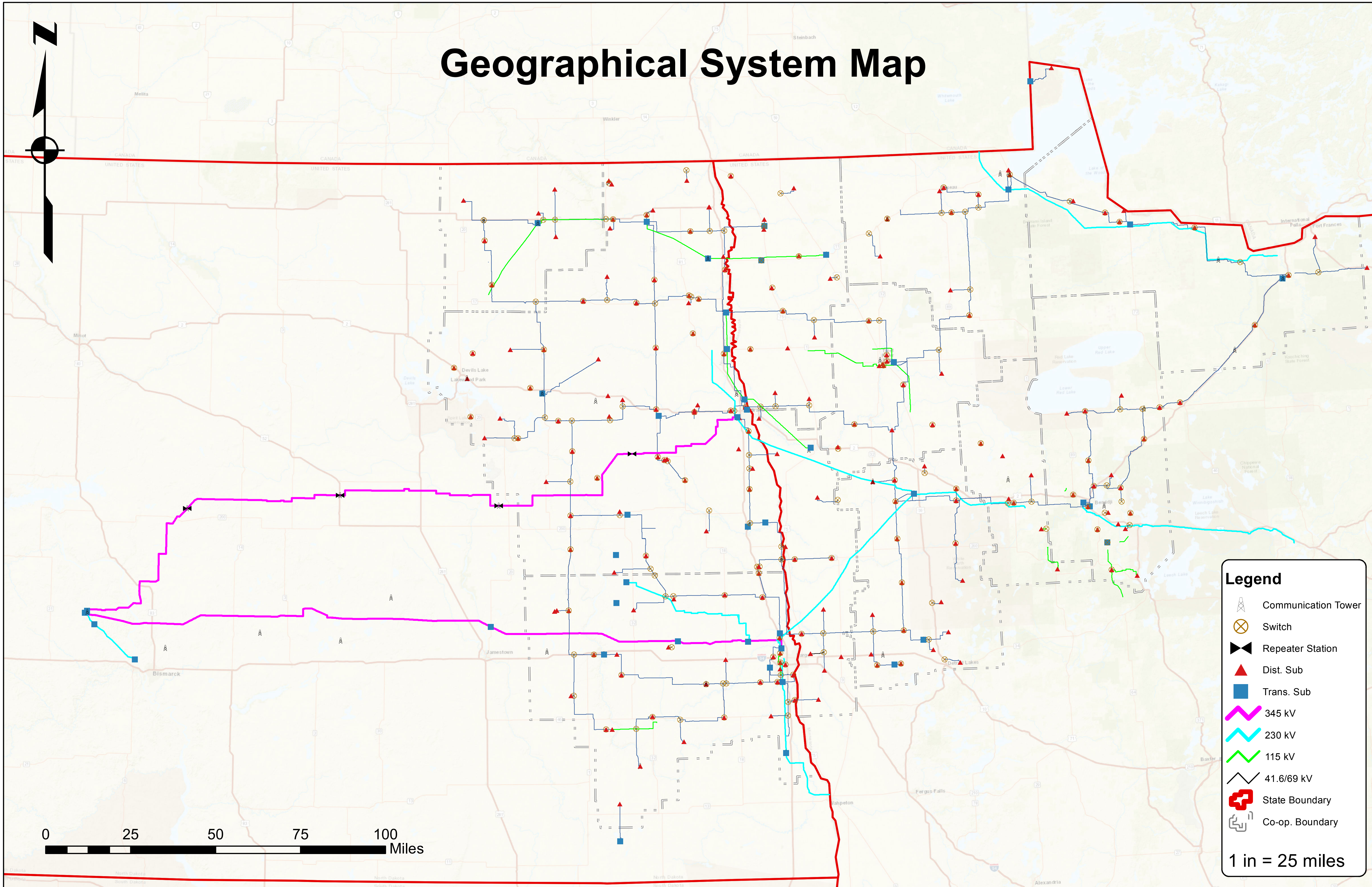
Code

Private
Public
Co-op

APPENDIX B

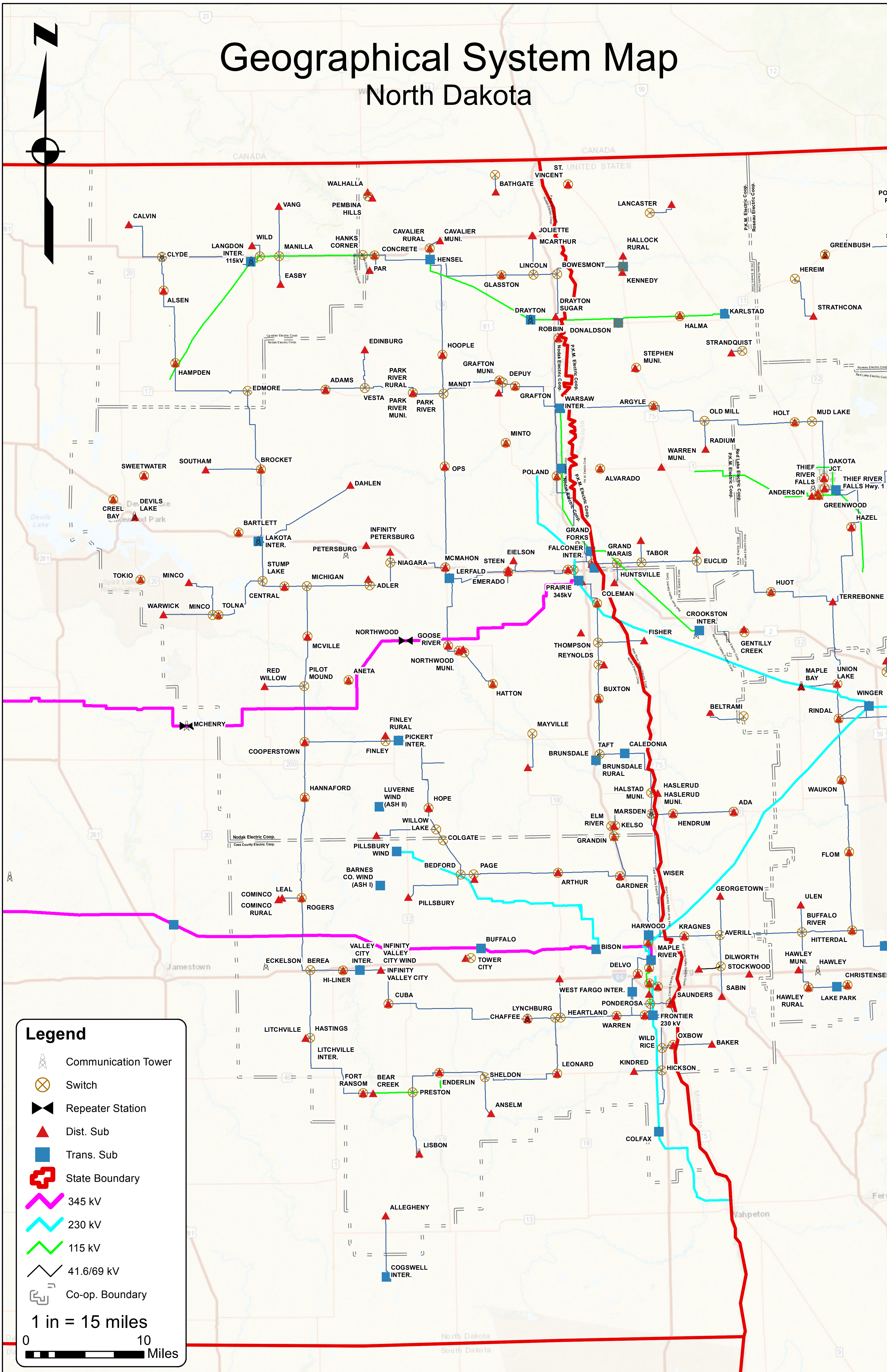
Minnesota Service Area Maps

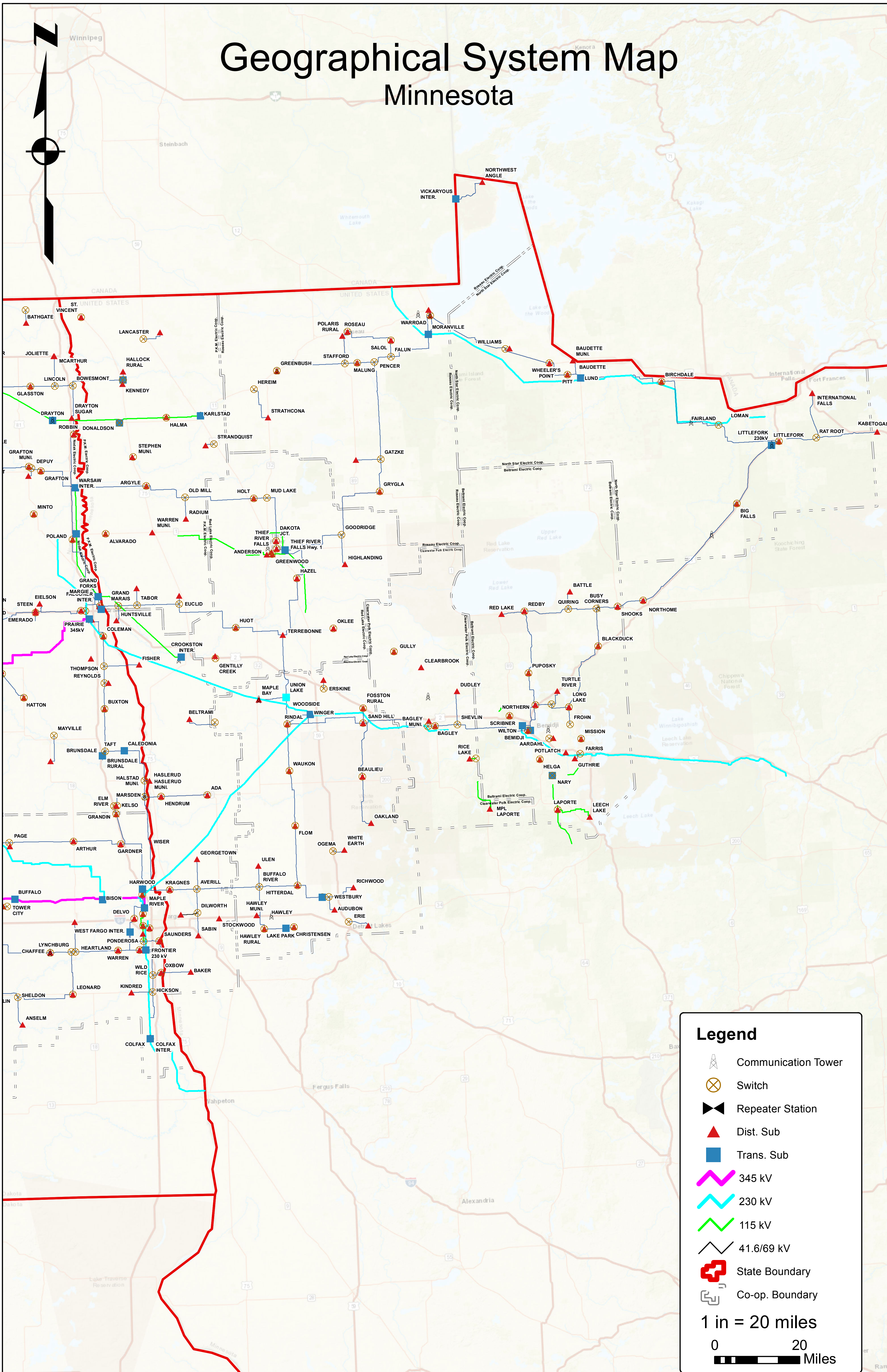
Geographical System Map



Geographical System Map

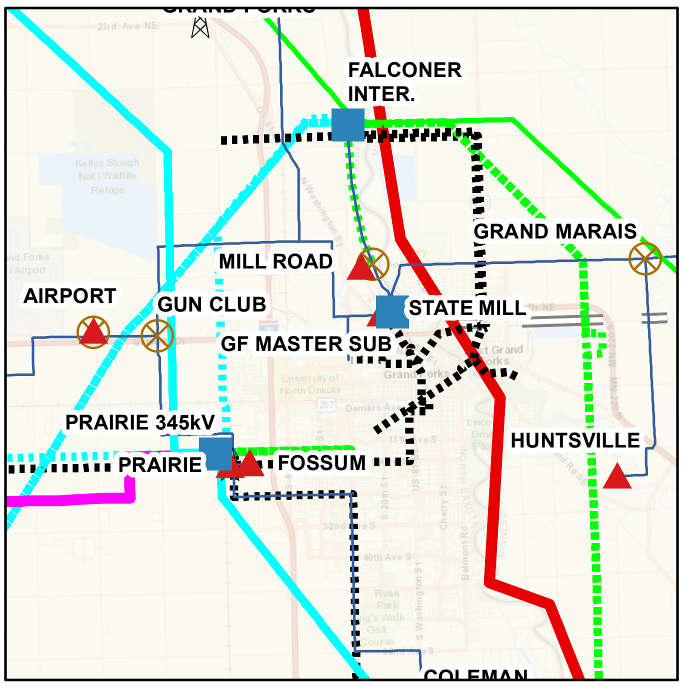
North Dakota



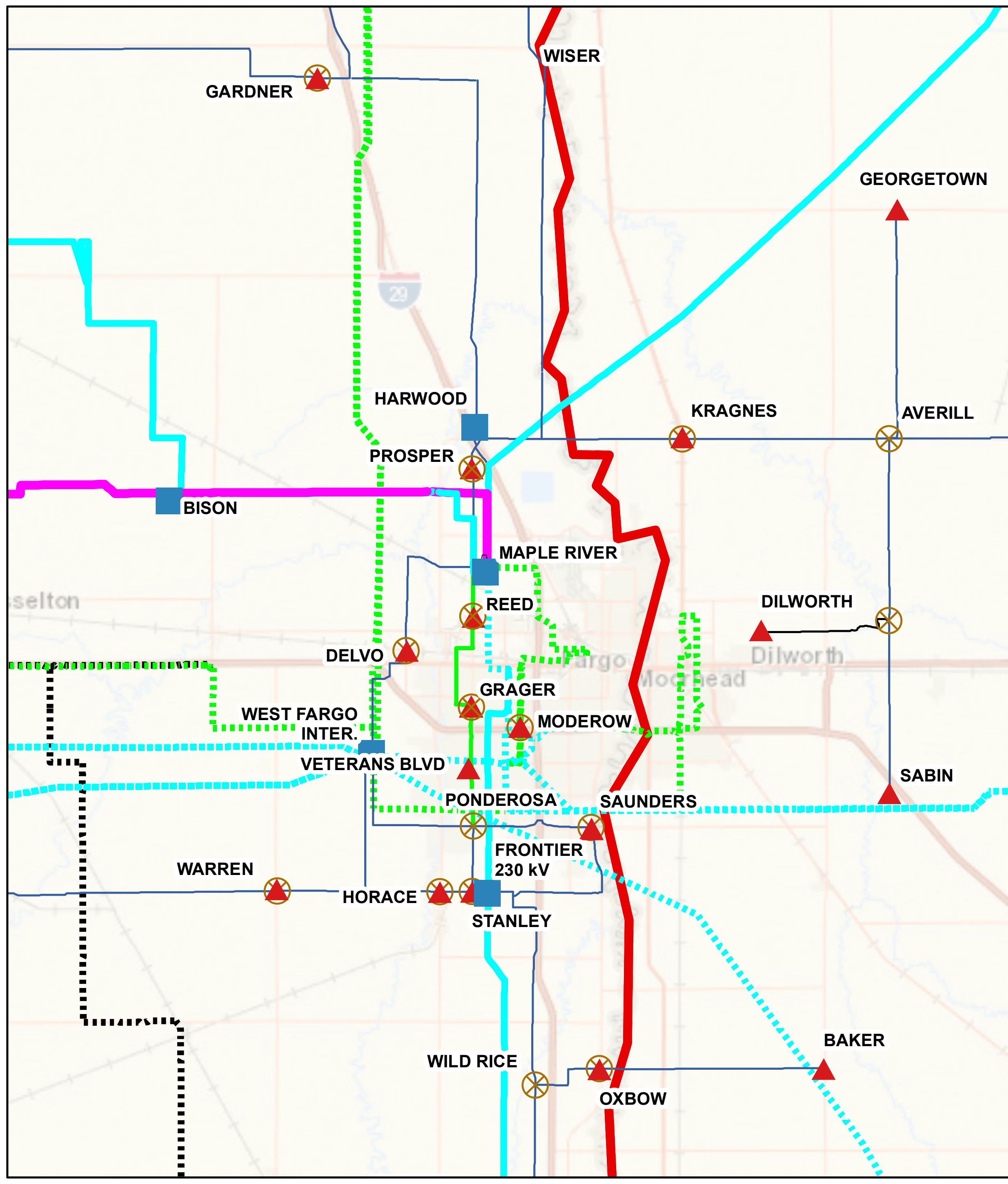


Geographical System Map
Minnesota
Legend
Communication Tower
Switch
Repeater Station
Dist. Sub
Trans. Sub
345 kV
230 kV
115 kV
41.6/69 kV
State Boundary
Co-op. Boundary
1 in = 20 miles
0
20
Miles

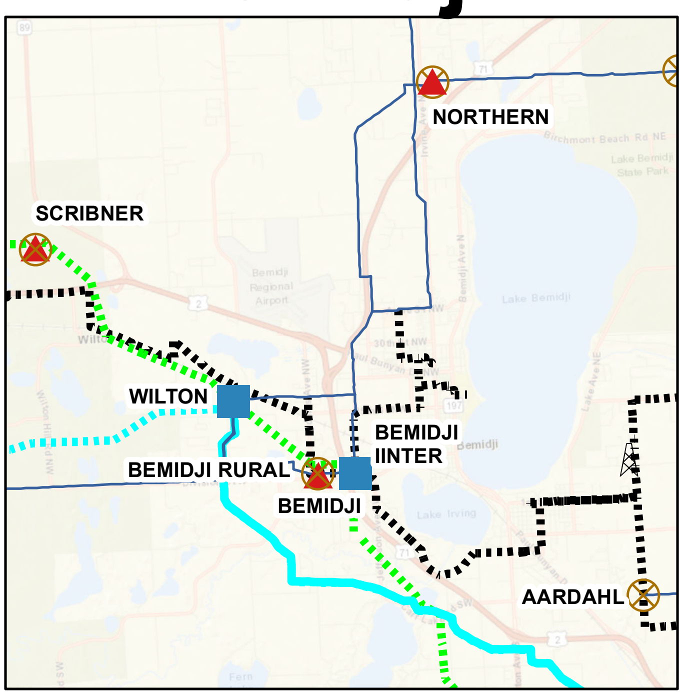
Grand Forks



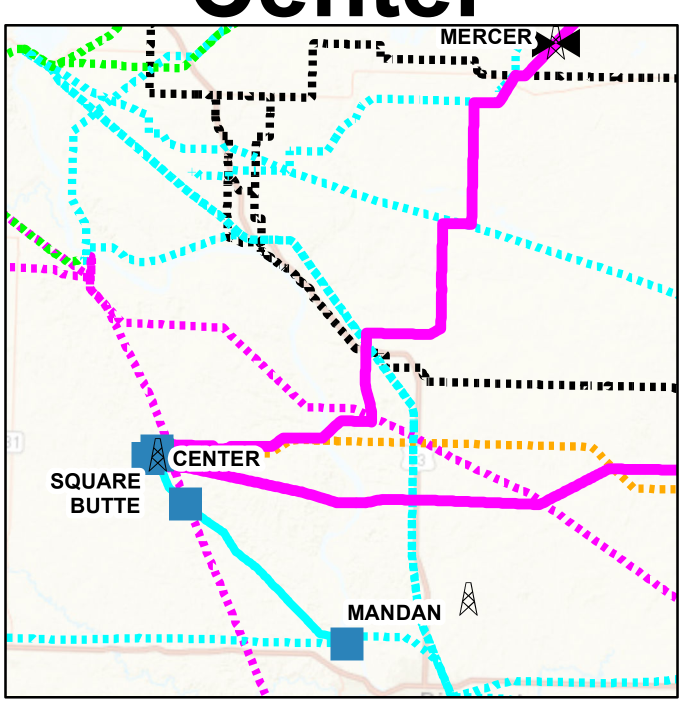
Fargo



Bemidji



Center



Thief River Falls