




A Touchstone Energy® Cooperative 

July 1, 2024

Secretary to the Commission
North Dakota Public Service Commission
State Capitol Building
Bismarck, North Dakota 58505

Dear Sir:

In accordance with Section 49-22-04 of the North Dakota Century Code, Square Butte Electric Cooperative herewith files the enclosed Ten-Year Plan with the North Dakota Public Service Commission.

Any questions concerning the contents of the enclosed document should be directed to me.

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

A handwritten signature in blue ink, appearing to read "Jamie Overgaard".

Jamie Overgaard
Resource Planning Department

Enclosure

TEN-YEAR PLAN



Grand Forks, North Dakota

Prepared for the North Dakota Public Service Commission
Pursuant to Section 49-22-04 of the
North Dakota Century Code

MPC
Resource Planning Department

July 2024

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SQUARE BUTTE ELECTRIC COOPERATIVE

TEN-YEAR PLAN

INTRODUCTION

Square Butte Electric Cooperative was organized in May 1972 as a cooperative corporation under the laws of the State of North Dakota. As a generation and transmission cooperative, Square Butte is owned by 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota.

Square Butte owns the Milton R. Young 2 plant, a 455-megawatt (MW) lignite-fired steam generator co-located at the Milton R. Young Station near Center, N.D. Minnkota is the operating agent for the Young 2 generator. The output of the Young 2 plant is allocated to Minnkota Power of Grand Forks, N.D., and Minnesota Power of Duluth, Minn., at a ratio of 50% to each utility (227,500 kW). In addition to its 50% allocation, Minnkota currently purchases 41.2% of the output of the plant from Minnesota Power, with increasing increments until 2026, at which point Minnkota will receive 100% of the electrical energy produced by Young 2.

Energy generated by the Young 2 plant transmitted to the Red River Valley through the 250-mile, 345-kilovolt (kV) Center to Grand Forks (CGF) transmission line, which is owned and operated by Minnkota. Prior to the completion of the CGF line in 2014, Young 2 energy was transmitted via the Center to Duluth DC line, which is now owned and operated by Minnesota Power.

SECTION A: Existing Energy Conversion Facilities

1. See Exhibit 1- - U.S. Department of Energy Form EIA-923
OTP is responsible for Form EIA-923 for the Coyote facilities.

SECTION B: Energy Conversion Facilities Under Construction

None

SECTION C: Proposed Energy Conversion Facilities on Which Construction is Intended Within the Ensuing Five Years

Square Butte Electric Cooperative continues to support Minnkota’s evaluation of Project Tundra, an initiative to build a carbon capture and storage facility at the Young Station. The facility is designed to capture up to 4 million metric tons of CO₂ annually before safely and permanently storing the CO₂ in geologic formations one to two miles below the plant site. The carbon capture system will utilize Mitsubishi Heavy Industries Advanced KM CDR Process, and will capture approximately 95% of the CO₂ emissions from the flue gas that is processed. When both Young Station units are operating at full output, the carbon capture system is designed to process 100% of the flue gas from Unit 2, and about 20% of the flue gas from Unit 1

Another driver for Minnkota’s pursuit of Project Tundra 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 risk to maintaining affordable and reliable resources. If constructed, Project Tundra could help provide continued reliability and affordability of electricity from the power plant, while preserving prior plant infrastructure investment. Using a technology-driven solution can help to reduce risk to our member-owners given the uncertainty of future CO₂ regulations.

Project Tundra is currently in its final stage of development with partners TC Energy (commercialization lead and a potential investor), Mitsubishi Heavy Industries (lead technology provider) and Kiewit (construction lead). Together, these entities continue to work under an engineering, procurement and construction (EPC) model. The project has received important environmental approvals to ensure progress can continue forward. Project Tundra has access to the two largest permitted CO₂ storage facilities in the United States located near Center, N.D., which allows for the safe and permanent storage of 222 million tonnes of CO₂. Additionally, the state has also approved an air permit for the carbon capture facility.

Project Tundra is fortunate to have significant state and federal support. The project secured \$250 million in low-interest loans through North Dakota’s Clean Sustainable Energy Authority (CSEA) and is the recipient of U.S. Department of Energy (DOE) funding through its Carbon Capture Demonstration Projects Program. The DOE funding is under award negotiation for up to \$350 million.

With project activities continuing to ramp up, Minnkota continues working closely with member cooperatives, local landowners, community members and other key stakeholders. Consistent landowner meetings are held, project leaders present to county and state officials, and educational sessions have been held with member system board directors and staff. Minnkota is committed to keeping open lines of communication as the project moves ahead.

More details of Project Tundra can be found at www.projecttundrand.com.

SECTION D: Proposed Energy Conversion Facilities During the Next Ten-Year Time Period

Square Butte does not have plans for energy conversion facilities in the next ten years.

SECTION E: Existing Transmission Facilities (Electric)

Square Butte owns one Transmission Facility, a 230 kV line which connects Milton R. Young Unit 2 to the grid at the Square Butte substation. Square Butte also owns the west portion of the Square Butte substation. These facilities were completed in 1976.

Square Butte does not have plans to retire any transmission facilities in the ensuing ten years.

SECTION F: Existing Transmission Facilities (Pipeline)

1. See Exhibit III
2.
 - a. Product type: water
 - b. Length of facilities in miles: 13
 - c. Pipe size: 30 inches
 - d. Maximum design operating pressure: 800 pounds per square inch
 - e. Maximum design flow rate: 30 cubic feet per second
 - f. Pump specifications: two 1500-horsepower electric motors with a capacity of 6740 gpm
 - g. Minimum cover over pipe: 7 feet
3. March 1977
4. None

SECTION G: Proposed Transmission Facilities on Which Construction is Intended Within the Ensuing Five Years (Electric)

Square Butte does not have plans for constructing proposed transmission facilities in the next five years.

SECTION H: Proposed Transmission Facilities on Which Construction is Intended Within the Ensuing Five Years (Pipeline)

Square Butte does not have plans for constructing proposed transmission facilities in the next five years.

SECTION I: Proposed Transmission Facilities During the Next Ten-Year Time Period (Electric and Pipeline)

Square Butte does not have additional plans for proposed Transmission Facilities or Pipeline Facilities beyond the next ten years.

SECTION J: Regional Coordination

See Minnkota Power Cooperative's Ten-Year Plan

SECTION K: Environmental Information

See Minnkota Power Cooperative's Ten-Year Plan

SECTION L: Projected Demand for Service

See Minnkota Power Cooperative's Ten-Year Plan

EXHIBIT I

U.S. Department of Energy Form EIA-923
(Supersedes U.S. Department of Energy Form EIA-767)
(Supersedes FERC Form 67)

NOTICE: This report is mandatory under the Federal Energy Administration Act of 1974 (Public Law 93-275). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning confidentiality of information in the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

SCHEDULE 1. IDENTIFICATION

Is this a regulated utility plant

Yes No

Is this a combined heat and power plant

Yes No

Enter the total plant efficiency of the combined heat and power plant

%

Survey Contact

Contact Brenda Sem Submit Date 28-MAR-24
Title Accounting Manager
Address 5301 32nd Ave
City/State/Zip Grand Forks ND 58201
Email bsem@minnkota.com Phone (701) 795-4270 Fax

Supervisor of Contact Person for Survey

Contact Melanie Skjoiten
Title
Address
City/State/Zip
Email mskjoiten@minnkota.com Phone (701) 795-4258 Fax

Report For

Company Name Minnkota Power Coop, Inc
Plant Name Milton R Young
Plant ID 2823 Plant County Oliver
Plant Address 3401 24th Street S.W.
Plant City Center Plant State ND

For contact detail go to <http://www.eia.doe.gov/oss/forms.html#eia-923>

SCHEDULE 6. NONUTILITY ANNUAL SOURCE AND DISPOSITION OF ELECTRICITY

(Instructions for SCHEDULE 6 are on page 13)

SCHEDULE 6 collects calendar year data (no monthly detail).

Report all generation in **megawatthours (MWh)** rounded to a whole number.

- | | |
|--------------------------------|---|
| (1) Gross Generation (Annual) | (4) Station Use |
| (2) Other Incoming Electricity | (5) Direct Use |
| | (6) Total Facility Use (4 + 5) |
| | (7) Retail Sales to Ultimate Customers |
| | (8) Sales for Resale (MWh) |
| | (9) Provided Tolling Agreement (MWh) |
| | (10) Other Outgoing Electricity |
| (3) Total Sources (1 + 2) | (11) Total Disposition (6 + 7 + 8+ 9+ 10) |

Total Sources must equal Total Disposition (3 = 11)

Plants that cannot separate Station Use and Direct Use may enter zero in Station Use and the sum of Station Use and Direct Use in the Direct Use field.

Types of Other Incoming Electricity
List all of the types of incoming electricity included in (2)
Other Incoming Electricity

Types of Other Outgoing Electricity
List all of the types of outgoing electricity in item (10)
Other Outgoing Electricity

SCHEDULE 7. PART A. ANNUAL REVENUES FROM SALES FOR RESALE TOAL

Complete Schedule 7, Part A, only if a positive value was entered on Schedule 6, Item (8): "Sales for Resale."

Sales for Resale are energy supplied to electric utilities, cooperatives, municipalities, federal and state elecctyic agencies, power marketers, or other entities, for resale to end-use consumers.

Report in thousand dollars. For example \$1,987,234 should be entered as 1,987

Annual Revenues from Sales for Resale (in thousand dollars)

SCHEDULE 7. PART B. ANNUAL RETAIL SALES, REVENUES AND NUMBER OF CUSTOMERS FROM RETAIL SALES

Report by state and end-use customer sectors (Residential, Commercial, industrial and Transportation).

Complete an individual Schedule 7, Part B, for each state where customers are located, only if a positive value was entered on Schedule 6, Item (7), "Retail Sales to Ultimate Customers."

Annual Retail Sales, Revenue, and Number of Customers:

- Retail sales are sold directly to an end-use customer (i.e., the energy is consumed by the customer, onsite, and is not resold to other customers).
- Enter annual retail sales, revenue, and number of customers for each state where customer(s) are located.
- Report Annual Retail Sales in megawatthours (Mwh), by sector.
- Report Annual Revenue in thousand dollars, by sector.
- Report Number of Customers, by sector.

State					
Items	Residential	Commercial	Industrial	Transportation	Total
Retail Sales (Mwh)					
Revenue (\$ 000's)					
Number of Customers					

SCHEDULE 8. PART B. FINANCIAL INFORMATION RELATED TO COMBUSTION BY-PRODUCTS

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermoelectric power plant with a total steam turbine capacity greater than, or equal to, 100 megawatts.

- Data reported in Schedule 8, Part B must correspond to the combustion by-product data reported on Schedule 8, Part A.
- If actual data are not available, provide an estimate value.
- Report all values in thousand dollars, to the nearest thousand.

Operation and Maintenance (O&M) Expenditures During Year (Thousand Dollars)

Type	(1) Fly Ash	(2) Bottom Ash	(3) Flue Gas Desulfurization	(4) Water Pollution Abatement	(5) Other Pollution Abatement	(6) Total (1 + 2 + 3 + 4 + 5)
Collection	18,450	1,957	14,639	278		35,324
Disposal	807	943	1,590	22		3,362
Other					4,757	4,757

Capital Expenditures for New Structures and Equipment During Year, Excluding Land and Interest Expense (Thousand Dollars)

Type	(7) Air Pollution Abatement	(8) Water Pollution Abatement	(9) Solid/Contained Waste	(10) Other Pollution Abatement
Amount	9	0	12,626	0

Byproduct Sales Revenue During Year (Thousand Dollars)

Type	(11) Fly Ash	(12) Bottom Ash	(13) Fly and Bottom Ash Sold Intermingled	(14) Flue Gas Desulfurization	(15) Other Byproduct Revenue	(16) Total (11+12+13+14+15)
Amount	0	302	0	0	0	302

SCHEDULE 8. PART C. AIR EMISSIONS CONTROL INFORMATION

Annual Operations

Environmental Equipment and/or Technology Type					Status	Hours in Service	NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control				Mercury Control		Acid Gas Control
Types	PM Control ID	SO2 CONTROL ID	NOX Control ID	Mercury Control			Entire Year	May through September	Emission Rate (0.01 lb/MMBtu)	Removal Efficiency Rate at AOF	Tested Efficiency Particulate Removal (at 100% Load)	Test Date MM-YYYY	Removal Efficiency Rate at AOF	Removal Tested Efficiency (at 100% Load)	Test Date MM-YYY	Quantity of FGD Sorbent Used (nearest 0.1 thousand tons)	FGD Unit Electrical Energy Consumption	Removal Efficiency (nearest 0.1% by weight)	Emission Rate (0.01 lbs / Tbtu)
SP		FGD1		MC1	OP	8282							98.7	12-2023	16.8	9577.3	2.70		
SP		FGD2		MC2	OP	7333							94.3	12-2023	28	26110.2	3.09		

FGD Operation and Maintenance Expenditures During Year, Excluding Electricity (Thousand Dollars)

Flue Gas Desulfurization Unit ID	Feed Materials and Chemicals	Land and Supervision	Waste Disposal	Maintenance, Material and All Other Costs	Total
FGD1	\$3,830	\$928	\$492	\$929	\$6,179
FGD2	\$6,151	\$1,186	\$913	\$1,664	\$9,914

SCHEDULE 8. PART D. COOLING SYSTEM INFORMATION, MONTHLY OPERATIONS

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- **Complete a separate schedule for each reporting month.**
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Per month (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)						Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)			
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption	
Report Month 1																		
CS1	OC	OP	708	.777	0	112319	112319	0	4	50	56	66	74	1	0	4772.5	4772.5	0
Report Month 2																		
CS1	OC	OP	672	.723	0	106581	106581	0	4	48	58	65	74	1	0	4297.3	4297.3	0
Report Month 3																		
CS1	OC	OP	743	1.584	0	117841	117841	0	4	46	58	64	77	1	0	5253.4	5253.4	0
Report Month 4																		
CS1	OC	OP	652	.73	0	106828	106828	0	4	57	67	72	84	1	0	4178	4178	0
Report Month 5																		
CS1	OC	OP	716	1.421	0	113611	113611	0	4	74	83	89	108	1	0	4883	4883	0
Report Month 6																		
CS1	OC	OP	671	1.56	0	110044	110044	0	4	83	92	99	112	1	0	4433.4	4433.4	0

SCHEDULE 8. PART D. COOLING SYSTEM INFORMATION, MONTHLY OPERATIONS

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.
 - **Complete a separate schedule for each reporting month.**
 - Complete a separate row for each cooling system.
 - If actual data are not available, provided an estimated value.
 - If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Per Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)						Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)			
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption	
Report Month 7																		
CS1	OC	OP	744	1.958	0	118000	118000	0	4	86	93	104	112	1	0	5267.5	5267.5	0
Report Month 8																		
CS1	OC	OP	744	2.024	0	118000	118000	0	4	81	92	98	112	1	0	5267.5	5267.5	0
Report Month 9																		
CS1	OC	OP	678	1.937	0	111183	111183	0	4	78	82	94	105	1	0	4525.6	4525.6	0
Report Month 10																		
CS1	OC	OP	523	1.285	0	82974	82974	0	4	66	81	92	110	1	0	2604.5	2604.5	0
Report Month 11																		
CS1	OC	OP	360	.663	0	59000	59000	0	4	53	61	85	98	1	0	1274.7	1274.7	0
Report Month 12																		
CS1	OC	OP	372	.655	0	59000	59000	0	4	51	56	75	91	1	0	1316.9	1316.9	0

SCHEDULE 8. PART D. COOLING SYSTEM INFORMATION, MONTHLY OPERATIONS

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- **Complete a separate schedule for each reporting month.**
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Hours of Service Per month	Annual Amt of Chlorine added to Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)					Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)			
					Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 1																		
CS2	OC	OP	744	1.226	0	250000	250000	0	4	48	54	65	74	1	0	11160	11160	0
Report Month 2																		
CS2	OC	OP	506	.815	0	170148	170148	0	4	47	57	72	101	1	0	5169.4	5169.4	0
Report Month 3																		
CS2	OC	OP	475	1.582	0	159597	159597	0	4	47	57	62	77	1	0	4548.1	4548.1	0
Report Month 4																		
CS2	OC	OP	720	1.455	0	241935	241935	0	4	55	65	68	84	1	0	10451.6	10451.6	0
Report Month 5																		
CS2	OC	OP	744	2.007	0	250000	250000	0	4	74	83	89	103	1	0	11160	11160	0
Report Month 6																		
CS2	OC	OP	618	1.943	0	207591	207591	0	4	83	91	98	111	1	0	7694.8	7694.8	0

SCHEDULE 8. PART D. COOLING SYSTEM INFORMATION, MONTHLY OPERATIONS

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.
 - **Complete a separate schedule for each reporting month.**
 - Complete a separate row for each cooling system.
 - If actual data are not available, provided an estimated value.
 - If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Hours of Service Per month	Annual Amt of Chlorine added to Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)					Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)			
					Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 7																		
CS2	OC	OP	744	2.894	0	250000	250000	0	4	85	93	104	114	1	0	11160	11160	0
Report Month 8																		
CS2	OC	OP	454	1.862	0	152413	152413	0	4	80	92	83	113	1	0	4147.9	4147.9	0
Report Month 9																		
CS2	OC	OP	654	3.162	0	219788	219788	0	4	77	82	91	100	1	0	8265.7	8265.7	0
Report Month 10																		
CS2	OC	OP	659	2.46	0	221500	221500	0	4	65	81	76	100	1	0	8760.6	8760.6	0
Report Month 11																		
CS2	OC	OP	720	1.99	0	241935	241935	0	4	52	60	63	78	1	0	10451.6	10451.6	0
Report Month 12																		
CS2	OC	OP	692	1.793	0	232433	232433	0	4	49	55	63	72	1	0	9646.7	9646.7	0

SCHEDULE 9. COMMENTS
(Instructions for SCHEDULE 9. are on page 20.)

Schedule	Part	Item	Comments
8	C	OT	B1 Oxidize Halide
8	C	OT	B2 Oxidize Halide

Generator Retirement Dates

Generator Id	Retirement Month	Retirement Year	Comments
			Changes in Ownership (Provide name of purchaser and date sold.)

ERRORS

Purchase Type	Fuel	Schedule	Prime Mover	Equipment ID	Rpt Month	Supplier	Error Number & Description	Ranges	Override Comment
		8C		FGD1/S			851 The Removal Efficiency tested at 100% load for sulfur dioxide is outside the expected range of 50%-99%. If correct, enter a comment to explain data out of typical range.		Input is not out of range, input is at 98.7% which is within the 50-99% range

EXHIBIT II

Federal Energy Regulatory Commission Form FERC-714
(Supersedes FERC Form 12)



**Annual Electric Balancing Authority Area and Planning
Area Report**

For the Year Ending December 31, 2023

Part I - Schedule 1. Identification and Certification

1. Respondent Identification:

Code:
12658

Name:
Minnkota Power Cooperative, Inc.

2. Respondent Type: (Please check appropriate box and fill in name)

Part I: Balancing Authority Area (Complete Parts I, II, and IV)

Unit dispatch is not based on the economic dispatch of thermal units (i.e., a system lambda is not calculated)

Balancing Authority Area Name:

Part II: Planning Area (Complete Parts I, III, and IV)

Planning Area Name:
Minnkota Power Cooperative, Inc.

3. Respondent Mailing Address:

5301 32nd Ave South, Grand Forks, ND 58201

4. Contact Person:

Name:
Dan Trebil

Title:
Manager Energy Supply

E-mail address:
dtrebil@minnkota.com

Telephone #:
701-795-4424

Ext:

5. Certifying Official:

Name:
Todd Sailer

Title:
Vice President, Power Supply

Date:
05/21/2024

This report is an Original Revised Filing

**Annual Electric Balancing Authority Area and Planning
Area Report**

For the Year Ending December 31, 2023

Part II - Schedule 1. Generating Plants Included in Reporting Balancing Authority Area

Under the name of its operating electric utility, list all generating plants (1) within the respondent's balancing authority area which are controlled, metered or for which the required information is otherwise available to balancing authority area operators and (2) dynamically scheduled plants or units outside the balancing authority area. Specifically identify dynamically scheduled plants. Report only plant totals with generators in an operating or standby status. Provide totals for columns (d) and (e) as a last line. The total in column (d) should equal the value in column (c) on Schedule 2 for the month of the annual peak demand. The total in column (e) should equal the value in column (f) on Schedule 3 for the month of the annual peak demand. Any differences must be explained in a footnote. Refer to the Form 714 instructions for specific guidelines.

Line No. (a)	Electric Utility Name (b)	Plant Name (c)	Plant Available Capacity at the Hour of the Annual Peak Demand on Net Energy for Load (MW)	Integrated Net Load on the Plant at the Hour of the Annual Peak Demand Based on Net Energy for Load (MW)
			(d)	(e)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
		TOTAL		

**Annual Electric Balancing Authority Area and Planning
 Area Report**

For the Year Ending December 31, 2023

Part II - Schedule 2. Balancing Authority Area Monthly Capabilities at Time of Monthly Peak Demand

The peak demand and other terms used in this schedule are defined in the Form 714 instructions. Please first read the instructions, then complete this Schedule. The value in column (c) for the month of the annual peak demand should equal the total in column (d) in Schedule 1. Any difference must be explained in a footnote.

Net Capability at the Time of the Monthly Peak Demand, Based on Balancing Authority Area Area Net Energy For Load (NEL)										
Line No. (a)	Month (b)	Net Capability from Plants Reported on Schedule II					External to the Balancing Authority Area Net Unit or Firm Capability (MW)			Total Capability (g + h + i) (MW) (j)
		Available Capability (MW) (c)	Unavailable Capability Due to:			Total (c + d + e + f) (MW) (g)	Available (MW) (h)	Not Available (MW) (i)		
			Planned Outage and Derating (MW) (d)	Unplanned Outage and Derating (MW) (e)	Other Outage and Derating (MW) (f)					
1	Jan									
2	Feb									
3	Mar									
4	Apr									
5	May									
6	Jun									
7	Jul									
8	Aug									
9	Sep									
10	Oct									
11	Nov									
12	Dec									

**Annual Electric Balancing Authority Area and Planning
Area Report**

Utility Code:12658
Utility Name:Minnkota Power Cooperative, Inc.

For the Year Ending December 31, 2023

Part II - Schedule 3. Balancing Authority Area Net Energy for Load and Peak Demand Sources by Month

Enter the monthly "Net Energy for Load" which is the amount of energy that the balancing authority area requires internally including balancing authority area losses. The total in column (d) should equal the difference in the totals for columns (e) minus (f) on Schedule 5. The value in column (f) for the month of the annual peak demand should equal the total in column (e) in Schedule 1. Any differences must be explained in a footnote. Refer to the Form 714 instructions for specific guidelines.

Line No. (a)	Month (b)	Balancing Authority Area Net Generation (MWh) (c)	Net Actual Interchange (MWh) (d)	Net Energy for Load (MWh) (c + d) (e)	Balancing Authority Area Area Load Sources at Time of Balancing Authority Area Area Monthly Peak Demand, Based on Net Energy For Load (NEL)					Monthly Minimum Demand (MW) (k)	
					Output of Generating Plants (MW) (f)	Unit or Firm Purchases (MW) (g)	Unit or Firm Sales (MW) (h)	Net Non-Firm & Inadvertent (MW) (i)	Monthly Peak Demand (MW) (f + g - h + i) (j)		
1	January										
2	February										
3	March										
4	April										
5	May										
6	June										
7	July										
8	August										
9	September										
10	October										
11	November										
12	December										
13	Total										

**Annual Electric Balancing Authority Area and Planning
 Area Report**

For the Year Ending December 31, 2023

Part II - Schedule 4. Adjacent Balancing Authority Area Interconnections

Identify on this schedule: each balancing authority area with which the respondent balancing authority area has actual or scheduled interchange of energy, in column (b); the total annual megawatthours (MWh) of the scheduled interchange that were received by the respondent balancing authority area through all interconnection points with each balancing authority area, in column (c); the MWh of scheduled interchange delivered to each balancing authority area, in column (d); the MWh of total annual actual interchange received and delivered within each adjacent balancing authority area, in columns (e) and (f). Provide totals for columns (c), (d), (e) and (f). The difference in the totals for columns (e) minus (f) should equal the total in column (d) on Schedule 3. Any difference must be explained in a footnote. Refer to the Form 714 instructions for specific guidelines.

Line No. (a)	Name of Adjacent Balancing Authority Area (b)	Balancing Authority Area Interconnection Line or Bus Names (c)	Line or Bus Voltage (kV) (d)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
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30			

**Annual Electric Balancing Authority Area and Planning
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For the Year Ending December 31, 2023

Part II - Schedule 5. Balancing Authority Area Scheduled and Actual Interchange

Identify on this schedule: each balancing authority area with which the respondent balancing authority area has actual or scheduled interchange of energy, in column (b); the total annual megawatthours (MWh) of the scheduled interchange that were received by the respondent balancing authority area through all interconnection points with each balancing authority area, in column (c); the MWh of scheduled interchange delivered to each balancing authority area, in column (d); the MWh of total annual actual interchange received and delivered within each adjacent balancing authority area, in columns (e) and (f). Provide totals for columns (c), (d), (e) and (f). The difference in the totals for columns (e) minus (f) should equal the total in column (d) on Schedule 3. Any difference must be explained in a footnote. Refer to the Form 714 instructions for specific guidelines.

Line No. (a)	Name of Balancing Authority Area (b)	Scheduled Interchange Between Balancing Authority Area Areas (MWh)		Actual Interchange Between Adjacent Balancing Authority Area Areas (MWh)	
		Received (c)	Delivered (d)	Received (e)	Delivered (f)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
	TOTAL				

**Annual Electric Balancing Authority Area and Planning
Area Report**

For the Year Ending December 31, 2023

Part II - Schedule 6. Description of Economic Dispatch

Disclosure of How Respondent Calculates System Lambda

**Annual Electric Balancing Authority Area and Planning
 Area Report**

For the Year Ending December 31, 2023

Part III - Schedule 1. Electric Utilities That Compose the Planning Area

Enter the name of each entity, including the respondent, that forms the planning area for which this report is being prepared and their coincident summer and winter peak demands in megawatts. Refer to the Form 714 instructions for specific guidelines.

Line No. (a)	Electric Utility Name (b)	Electric Utility Coincident Peak Demand (MW) (MWh)	
		Summer (c)	Winter (d)
1	Beltrami Electric Coop.	76	107
2	Red River Electric Coop.	23	31
3	Roseau Electric Coop.	25	35
4	Wild Rice Electric Coop.	49	71
5	Cass County Electric Coop.	259	246
6	Cavalier Rural Electric Coop.	9	7
7	Cleanwater Polk Electric Coop.	15	22
8	Northern Municipal Power Agency	84	74
9	Nodak Electric Coop.	177	190
10	North Star Electric Coop.	18	29
11	PKM Electric Coop.	22	25
12	Red Lake Electric Coop.	21	26

**Annual Electric Balancing Authority Area and Planning
 Area Report**

For the Year Ending December 31, 2023

Part III - Schedule 2. Forecast Summer and Winter Peak Demand and Annual Net Energy for Load

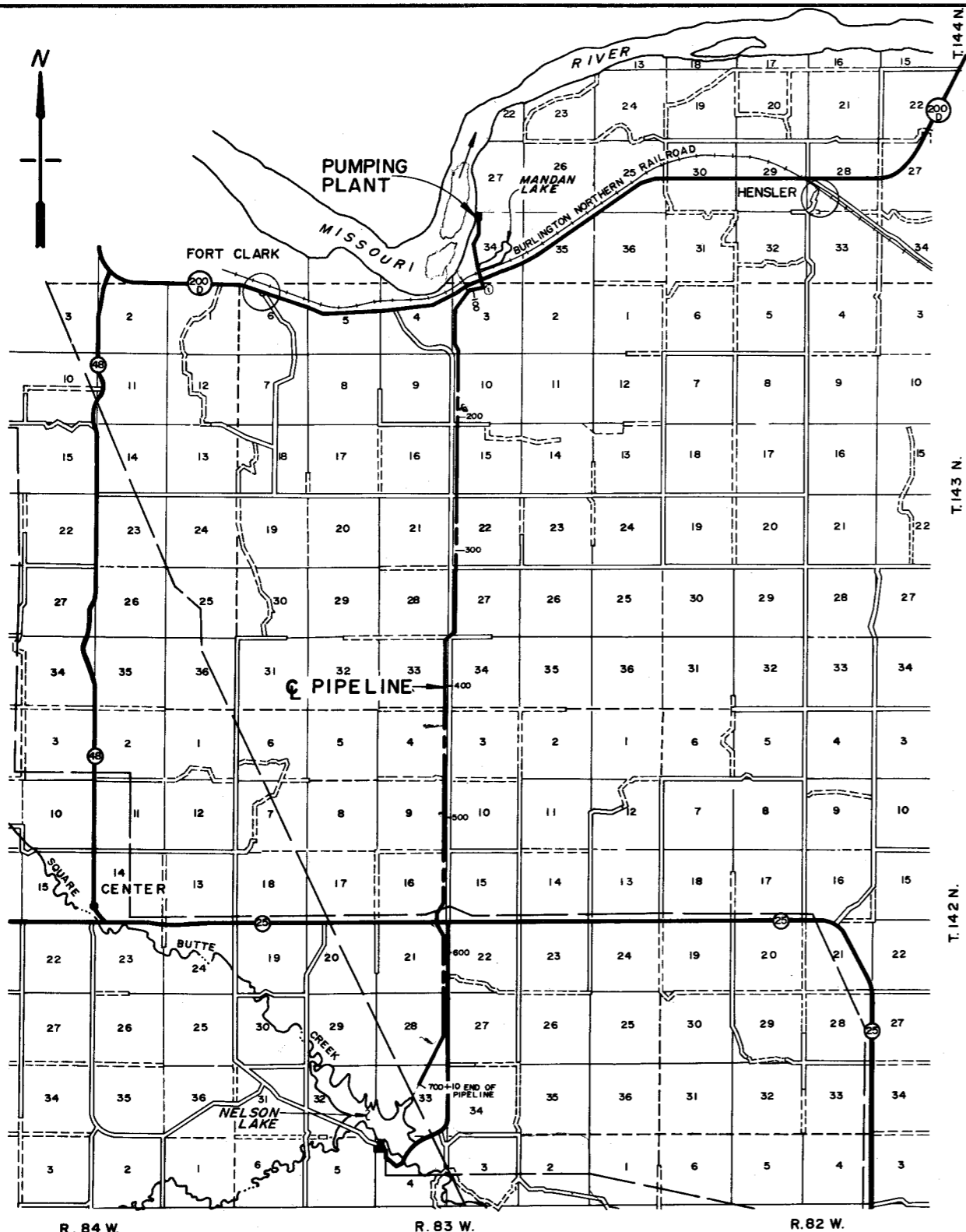
Provide the planning area's forecast summer and winter peak demand, in megawatts, and annual net energy for load, in megawatthours, for the next ten years.

Line No. (a)	Year (b)	Summer Forecast (MW) (c)	Winter Forecast (MW) (d)	Forecast of Annual Net Energy for Load (MWh) (e)
1	2024	768	922	4,676,930
2	2033	840	1,008	4,990,502
3	2025	776	931	4,710,388
4	2026	783	941	4,744,493
5	2027	791	950	4,778,779
6	2028	799	959	4,813,325
7	2029	807	969	4,848,267
8	2030	815	979	4,883,392
9	2031	823	989	4,918,765
10	2032	832	998	4,954,462

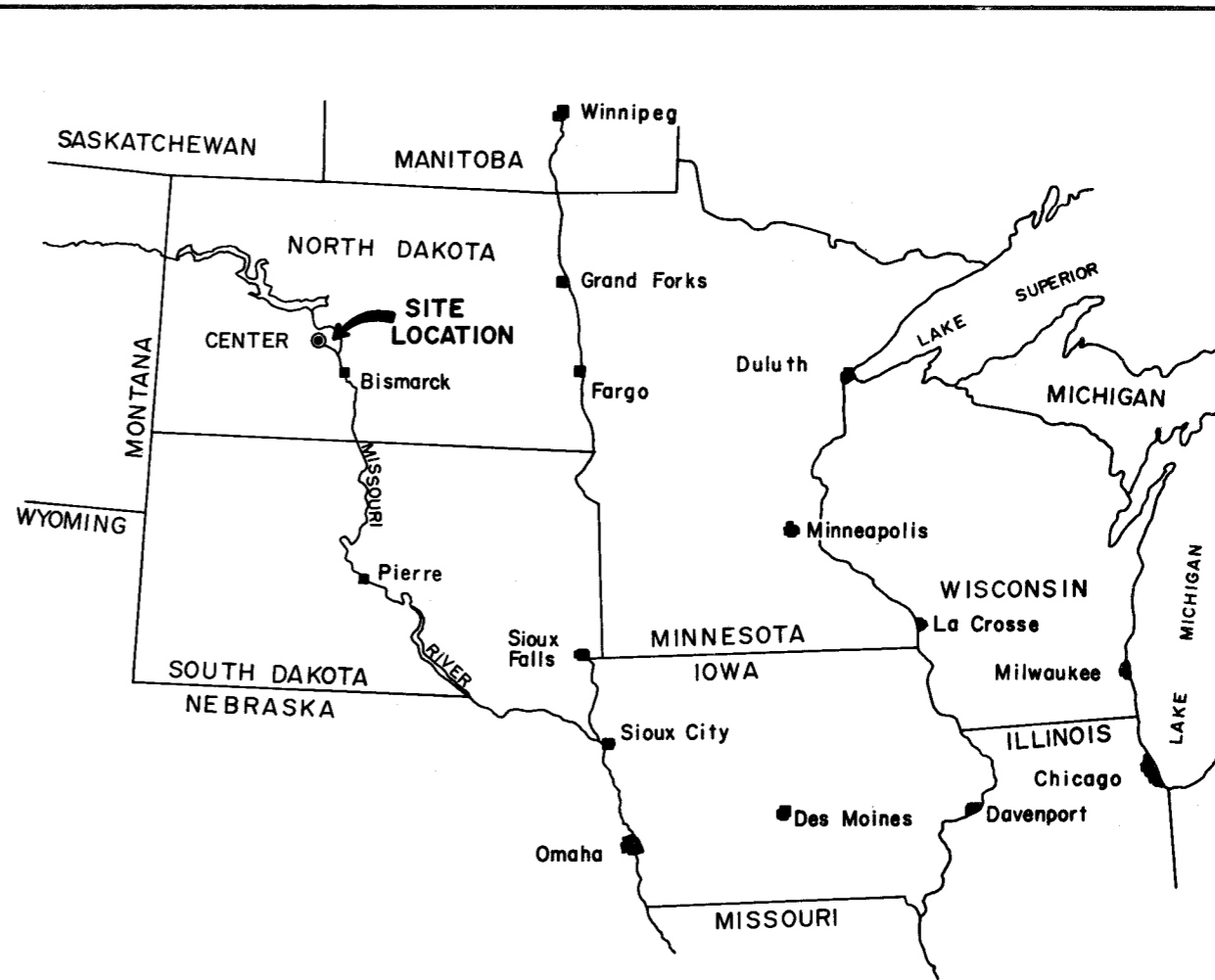
EXHIBIT III

Square Butte Electric Cooperative

Water Pipeline Map



SITE LOCATION
(OLIVER COUNTY)
SCALE IN MILES



LOCATION MAP
SCALE IN MILES

DESIGN AND DRAFTING DWG. <i>James W. Chambers</i> DATE 11-21-73 CHK. <i>Mervin L. Litchner</i> DATE 12/27/73		(SEAL) PREPARED UNDER RESPONSIBLE SUPERVISION OF <i>James W. Chambers</i> MICHIGAN PROFESSIONAL REGISTRATION NO. <u>1515</u> PROFESSIONAL REGISTRATION NO. <u>1515</u> AT OFFICES OF COMMONWEALTH ASSOCIATES INC. 209 E. WASHINGTON AVE., JACKSON, MICH.	OWNER AND LOCATION SQUARE BUTTE ELECTRIC COOPERATIVE GRAND FORKS, NORTH DAKOTA MILTON R. YOUNG STATION CENTER, NORTH DAKOTA		TITLE NELSON LAKE MAKEUP SYSTEM LOCATION & SITE MAP		
APPROVED <i>Mervin L. Litchner</i> DATE 12/27/73	JOB NO. 0971-005-032		DRAWING NO. 1	SHEET 1	REV.		
REV. DATE	DESCRIPTION	BY	APPROVED	REV. DATE	DESCRIPTION	BY	APPROVED