BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

June 26, 2024

Mr. Randy Christmann, Commissioner
North Dakota Public Service Commission
Capitol Building
600 E. Boulevard Ave. – Dept. 408
Bismarck, ND 58505

Dear Commissioner Christmann:

Pursuant to the requirements of the North Dakota Energy Conversion and Transmission Facility Siting Act, Basin Electric Power Cooperative hereby submits its Ten Year Plan.

Enclosed is an original and 9 copies of the plan.

Sincerely,

Todd Brickhouse
CEO & General Manager

lc
ATTACHMENT

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STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

AFFIDAVIT OF MAILING

I hereby certify that the following list contains the names and last address of each designated state agency and/or state official given notice of filing of the Basin Electric Power Cooperative Ten Year Plan pursuant to the Rules and Regulations of the North Dakota Public Service Commission governing the Siting of Energy Conversion and Transmission Facilities. I hereby certify that I have, by depositing letters of notice with the United States Postal Service, caused notice to be given all such state agencies and state officials that Basin Electric Power Cooperative has filed their Ten Year Plan with the North Dakota Public Services Commission.

Name	Last Known Address
See Exhibit A Attached	See Exhibit A Attached

Lisa Carney
Signature

On this 27 day of June 2024, Lisa Carney known to me, under oath deposed and said the above Affidavit of Mailing is true and correct.

DEBRA HAUSAUER NOTARY PUBLIC STATE OF NORTH DAKOTA
Seal
My Commission Expires 08/30/25

Debra Hausauer
Notary Public

Mail to: Public Service Commission
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EXHIBIT A

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BASIN ELECTRIC POWER COOPERATIVE

A Touchstone Energy® Cooperative

NORTH DAKOTA TEN YEAR PLAN

2024

Table of Contents

INTRODUCTION

Basin Electric Power Cooperative is a regional rural electric wholesale power supplier headquartered at 1717 East Interstate Avenue, Bismarck, North Dakota. The region served by Basin Electric includes all or portions of nine states encompassing Montana, Wyoming, Colorado, North Dakota, South Dakota, Nebraska, Minnesota, Iowa, and New Mexico. Basin Electric owns and operates or otherwise jointly shares energy conversion and transmission facilities throughout this region. Basin Electric is the parent company to six subsidiaries: Dakota Gasification Company, Dakota Coal Company, Montana Limestone Company, Wyoming Lime Producers, Souris Valley Pipeline LTD, and Nemadji River Generation LLC. A ten-year plan for Dakota Gasification Company will be submitted under separate cover by Dakota Gasification Company.

SECTION A: EXISTING ENERGY CONVERSION FACILITIES

Basin Electric owns all or portions of fifteen existing energy conversion facilities. Six of these facilities are in North Dakota; the Antelope Valley Station near Beulah; the Leland Olds Station near Stanton; Prairie Winds 1 near Minot; the Minot Wind Project near Minot; the Pioneer Generation Station near Williston; and the Lonesome Creek Station near Watford City. Other existing energy conversion facilities outside of North Dakota are the Laramie River Station at Wheatland, Wyoming; the Wyoming Distributed Generation in Wyoming; the Dry Fork Station near Gillette, Wyoming; the Spirit Mound Station at Vermillion, South Dakota; the Groton Generation Station near Groton, South Dakota; Crow Lake Wind Project near White Lake, South Dakota; Deer Creek Station near Brookings, South Dakota; Wisdom Unit 2 at Spencer, Iowa; and the Culbertson Generation Station near Culbertson, Montana. The Chamberlain Wind Project at Chamberlain, South Dakota, was decommissioned in October of 2023.

Basin Electric purchases all output from nine waste heat recovery units: three in North Dakota, three in South Dakota, and one each in Minnesota, Montana, and Iowa.

Basin Electric purchases output from nine wind facilities in North Dakota: ND 1Wind Energy Center, Wilton Wind Energy Center, Baldwin Wind, Sunflower, Brady 1, Brady 2, Lindahl, Northern Divide, and Aurora.

Basin Electric purchases output from five wind facilities in South Dakota: SD Wind Energy Center, Day County, Campbell County, Prevailing Winds, and North Bend. Basin Electric also purchases all output from the City of Madison Diesel Generators.

Basin Electric purchases all or portions of the following resources in Iowa: Unit #4 of the George Neal Station, Walter Scott Junior Energy Center Units 3 & 4, Wisdom Station Units 1 & 2, Spencer Combustion Turbine, Estherville Diesel Generation, Webster City Combustion Turbine, and three wind facilities.

The most recent Energy Information Administration (EIA) Form No. 923 for the Antelope Valley Station and the Leland Olds Station are included as Exhibit 1.

SECTION B: ENERGY CONVERSION FACILITIES UNDER CONSTRUCTION

Basin Electric is currently installing two additional combustion turbines and six additional natural gas reciprocating internal combustion engines at Pioneer Generation Station. See Section L.

SECTION C: PROPOSED ENERGY CONVERSION FACILITIES ON WHICH CONSTRUCTION IS INTENDED WITHIN THE ENSUING FIVE YEARS

Basin Electric currently has no Board-approved plans for construction of new generation facilities; however, it is evaluating new resource options to meet forecasted load growth as it materializes.

Basin Electric (through its subsidiary Nemadji River Generation, LLC), Dairyland, and ALLETE, Inc. (through its subsidiary South Shore Energy) are working together on the development of a natural gas combined cycle facility in Superior, Wisconsin. The proposed plant is estimated to have an installed capacity of 550-625 MW. Basin Electric announced ownership of 30% share of the project in September of 2021. In January of 2020, the project received a Certificate of Public Convenience and Necessity (CPCN) from the Public Service Commission of Wisconsin (WI). The WI Department of Natural Resources re-issued an air construction permit in September of 2023. The project is awaiting a Coastal Zone Consistency Determination from the Wisconsin Department of Administration and a wetland permit from the United States Army Corp of Engineers. The project entered an application with MISO in June 2017 to include the plant in the August 2017 generator interconnection study group. The Generation Interconnection Agreement was executed by all parties in 2020. The in-service date is currently estimated to be in 2029 but is subject to change until the necessary permits have been granted to the project.

SECTION D: PROPOSED ENERGY CONVERSION FACILITIES DURING THE NEXT TEN-YEAR TIME PERIOD

Basin Electric is currently siting up to a 1400 MW natural gas generation facility in northwestern North Dakota in response to sustained load growth in the region. This facility is targeting a commercial operation date in 2030 or earlier. Basin Electric is also evaluating renewable project opportunities under the Rural Utility Service New ERA program.

SECTION E: EXISTING TRANSMISSION FACILITIES (ELECTRIC)

Basin Electric's transmission and related substation facilities in North Dakota and their associated commercial dates are listed in the following table:

a. **TRANSMISSION LINES**

LINES - BY VOLTAGE	COMMERCIAL IN-SERVICE DATE
69 kV Lines	
Leland Olds - Basin Electric Sub	01/09/66

115 kV Lines

Basin Electric Sub - Stanton Tap	01/09/66
Logan-Kenmare Line	04/01/79
Logan-Mallard Line	04/01/79
Charlie Creek-Squaw Gap	12/31/82
Squaw Gap-Richland	12/31/82
Blaisdell-Berthold	12/21/13
Blaisdell-Plaza	02/01/18

230 kV Lines

Leland Olds #1-Washbum Double Circuit	01/09/66
Leland Olds-Logan Line	03/31/80
Leland Olds #2 - Basin Electric Sub	12/15/75
Logan- Blaisdell -Tioga	05/01/82
Tioga-Canadian Border (Estevan)	05/01/82
Belfield-Daglum-Rhame	04/07/10
Williston- Wheelock - Tioga	01/10/11
Judson-Williston	12/22/15
Tande-Neset	10/31/17
Neset-Northshore	01/18/23

345 kV Lines

Leland Olds-Groton-Watertown	12/15/75
Leland Olds-Chappelle Creek Line	12/15/75
Chapelle Creek -Ft. Thompson Line	12/15/75
Leland Olds-AVS North Line	11/30/83
Leland Olds-AVS South Line	07/01/84
Antelope Valley Station-Charlie Creek #1	11/30/83
Antelope Valley Station-Roundup	09/18/15
Roundup-Charlie Creek	09/18/15
Charlie Creek-Patent Gate	12/22/15
Patent Gate -Judson	12/22/15
Patent Gate-Kummer Ridge	09/27/16
Judson-Tande	10/31/17

500 kV Lines

Antelope Valley Station-Huron, SD (345 kV operation)	07/01/84

b. **SUBSTATIONS**

115 kV Wm. J. Neal Station Switchyard	04/01/52

230 kV Leland Olds Switchyard	01/09/66
230 kV Washburn, ND Switchyard	01/09/66
115 kV Stanton Tap Structure	01/09/66
230/115/69 kV BEPC Substation	01/09/66
345/230 kV Leland Olds Switchyard Addition	12/15/75
230/115 kV Dickinson, ND Substation	12/15/75
230/115 kV Logan Substation	04/01/79
345/115 kV Charlie Creek Substation	11/30/83
345 kV Antelope Valley Station Switchyard	11/30/83
230/115 kV Neset Substation	10/07/09
230 kV Rhame Substation	04/07/10
230/115 kV Blaisdell Substation	05/24/12
230/115 kV Wheelock Substation	10/16/12
345/230 kV Judson Substation	12/22/15
345/115 kV Roundup Substation	09/18/15
345/115 kV Patent Gate Substation	12/22/15
345/115 kV Kummer Ridge Substation	09/27/16
345/230 kV Tande Substation	10/31/17
230/115 kV Northshore	01/18/23

c. Basin Electric does not anticipate retiring any of its existing transmission facilities within the next ten (10) years.

SECTION F: EXISTING TRANSMISSION FACILITIES (PIPELINES)

Pipeline transmission facilities utilized by Basin Electric are water supply lines to the Leland Olds Station, Antelope Valley Station, a 12-mile-long natural gas fuel supply pipeline associated with the Groton Generation Station, and a 13-mile-long natural gas fuel supply pipeline associated with the Deer Creek Station. The Leland Olds water line is approximately one-quarter mile in length and is located on plant site property owned by Basin Electric.

The water supply line for Antelope Valley is a 42-inch diameter steel lined concrete pipe of approximately nine miles in length. The line runs directly north from the plant site to an intake structure and pumping station located on Lake Sakakawea. This line was designed and constructed as a joint use facility for Basin Electric and the adjacent Great Plains Synfuels Plant. The State of North Dakota's southwest water pipeline uses the same intake structure and pumping station as the Antelope Valley Station pipeline. The Basin Electric line was designed to have a maximum operating pressure of 160 PSI gauge and a flow rate of 30,000 GPM. The pipeline was constructed, with a minimum earth cover of 84 inches. The pipeline was placed in-service in 1984. A new parallel pipeline was installed in 2006, because of recurring failures of the existing line. The new line is steel pipe with the same design parameters. The old line will be maintained as a back-up facility. None of Basin Electric's pipeline facilities are projected for retirement within the next ten-year period.

Dakota Gasification Company constructed a 3.5 mile, 10-inch diameter natural gas pipeline, in late 2013, with the sole purpose to provide Antelope Valley with access to natural gas for use only during startup activities.

The Deer Creek Station water supply line is a 6-inch diameter PVC pipe approximately one mile in length. The line runs directly from the water supply wells north to the plant site.

SECTION G: PROPOSED TRANSMISSION FACILITIES ON WHICH CONSTRUCTION IS INTENDED WITHIN THE ENSUING FIVE YEARS (ELECTRIC)

Transmission studies are underway to analyze any other required transmission improvements to accommodate network load growth. Results of these studies may indicate the need for additional load serving transmission facilities. SPP undertakes a yearly Integrated Transmission Planning Process (ITP) that holistically looks at reliability, economic, and policy needs of the transmission system. The results of 2021 ITP study completed in January of 2022 indicated the need for additional transmission facilities in North Dakota. This includes the following to be completed by Basin Electric:

- Roundup - Kummer Ridge 345 kV line (~35 miles)
- Leland Olds - Finstad - Tande 345 kV line (~170 miles)
- Springbrook 345/115 kV substation approximately 24.5 miles from Judson 345 kV substation on the Judson – Tande 345 kV line

There are additional projects slated for completion by Mountrail Williams Electric Cooperative as component of the 2021 ITP portfolio.

The Tande-to-Saskatchewan (~58miles) and Wheelock-to-Saskatchewan 230-kV (~52 miles) transmission line project was deemed necessary to resolve deficiencies in the transmission capability by the Southwest Power Pool (SPP). The two circuits will provide export and import capabilities of up to 650 megawatts, strengthening the local and regional electric system.

The project was approved by the SPP Aggregate Transmission Service Study in 2022. SPP provided Basin Electric an Approved Reliability Network Upgrade notice. Basin Electric is the designated transmission owner for the upgrade in the United States, and SaskPower will complete the circuit within Canada.

See Exhibit 4 for planning corridor.

SECTION H: PROPOSED TRANSMISSION FACILITIES ON WHICH CONSTRUCTION IS INTENDED WITHIN THE ENSUING FIVE YEARS (PIPELINE)

Results of the resource development of new generating resources (refer to section D) will identify pipeline improvements necessary to support the supply required by the new resources. Generation studies are underway to analyze the required improvements to accommodate member load growth. Results of these studies may indicate the need for additional load serving generation facilities.

SECTION I: PROPOSED TRANSMISSION FACILITIES DURING THE NEXT TEN-YEAR TIME PERIOD (ELECTRIC AND PIPELINE)

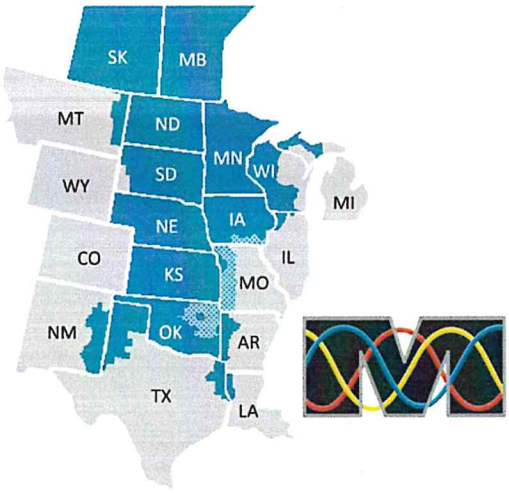
Results of the development of new generating resources (refer to section D) will identify transmission improvements necessary required by the new resources. Transmission studies are continuously ongoing to analyze any required transmission improvements to accommodate network load growth and economic dispatch. There are no additional projects planned in the ten-year time frame other than those listed in section G of this report.

SECTION J: REGIONAL COORDINATION

Midwest Reliability Organization

Midwest Reliability Organization (MRO) is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system (BPS) in the north central region of North America, including parts of both the United States and Canada. MRO is one of seven regional entities in North America operating under authority from regulators in the United States through a delegation agreement with the North American Electric Reliability Corporation (NERC) and in Canada through arrangements with provincial regulators. The region includes more than 200 organizations that are involved in the production and delivery of electricity including municipal utilities, cooperatives, investor-owned utilities, transmission system operators, federal power marketing agencies, Canadian Crown Corporations, and independent power producers.

The primary responsibilities of MRO are to ensure compliance with mandatory Reliability Standards by entities who own, operate, or use the interconnected, international BPS, to conduct regional assessments of the grid's ability to meet the demand for electricity, and to analyze regional system events.



Mid-West Electric Consumers Association

Basin Electric Power Cooperative is a member of the Mid-West Electric Consumers Association (Mid-West). Mid-West, which was founded in 1958, is a regional coalition of consumer-owned electric utilities that purchase power from

the federal multi-purpose projects in the Pick-Sloan Missouri Basin Program. The Association is governed by a board comprised of four directors from each state, with representation balanced between types of consumer-owned systems, and they meet four times a year. Mid-West's Water & Power Planning Committee meets throughout the year to assure timely consideration of issues and develops technical information and policy recommendations for consideration by the board of directors.

Southwest Power Pool

Basin Electric joined the Southwest Power Pool (SPP) in October of 2015. SPP oversees the bulk electric grid and wholesale power market in the central United States on behalf of a diverse group of utilities and transmission companies in 14 states including North Dakota. SPP establishes practices for system design, planning, adequacy, regional transmission service tariff, interconnections, operation, reliability, market designs and efficiency, and market power mitigation that will help to assure efficient and reliable power supply among the systems in SPP and SPP transmission customers. Basin Electric participates on various committees and work groups as a function of SPP. The SPP planning and interconnection processes are the main avenue for transmission project development in North Dakota.

Midcontinent Independent System Operator

MISO is a not-for-profit member-based organization that ensures reliable, least-cost delivery of electricity across all or parts of 15 U.S. states and one Canadian province. In cooperation with stakeholders, MISO manages more than 75,000 miles of high-voltage transmission and 191,000 megawatts of power-generating resources across its footprint.

Coordination with Area Utilities

Western Area Power Administration

Basin Electric coordinates regional power supplies with the Western Area Power Administration Upper Great Plains Region (WAPA UGPR). An example is the Miles City, Montana DC converter station. The station was built by the Western Area Power Administration (WAPA) to transfer electric power across the east/west transmission separation. Basin Electric has financed 40% of the cost of the station and contracted with WAPA for 40% of the capacity of the 200 MW station. This station enables Basin Electric to serve Central Montana Electric Power Cooperative and Members 1st Power Cooperative, Class A members with electrical loads primarily located west of the east-west separation. WAPA is also Basin Electric's transmission operator (TOP) for its transmission facilities in the eastern interconnection.

Montana-Dakota Utilities Co.

Member cooperatives of Basin Electric have a common service area in the western half of North Dakota with Montana-Dakota Utilities Co. (MDU).

The Tioga-Saskatchewan 230 kV line constructed by Basin Electric and Saskatchewan Power Corporation allows the purchase and sale of power among regional utilities. This line was reviewed with MDU and routed so that it could be tapped for future use by MDU and the member systems of Basin Electric. A result of this review was the Tioga 230/115 kV substation constructed by MDU and shared by Basin Electric.

The Miles City-Hettinger-New Underwood, South Dakota, 230 kV line is another example of joint planning. This line was jointly planned and constructed with WAPA, MDU and Basin Electric. Basin Electric and MDU each have 25% capacity rights and WAPA owns and has capacity rights to 50% of the line.

SECTION K: ENVIRONMENTAL INFORMATION

The primary obligation of Basin Electric is to provide an adequate wholesale supply of dependable, low-cost electric power to its member systems, consistent with the public interest. In conjunction with this, Basin Electric endeavors to maximize the socio-economic benefits associated with electrical generation and transmission projects and to minimize negative impacts associated with these projects. This is particularly true with respect to protecting the agricultural lifestyle and productivity of this region.

The Cooperative remains committed to preserving and enhancing the ecological balance of this region for the benefit of future generations. It is the policy of Basin Electric that environmental impacts be monitored, and steps taken to mitigate and alleviate adverse effects to the extent possible. Basin Electric has instituted a variety of programs designed to maximize the most efficient use of energy and to benefit the human, agricultural, and biological environments.

Projects proposed by Basin Electric that have a federal nexus adhere to the requirements of the associated Federal agency environmental policies and procedures which describe the procedures for compliance with the provisions of the National Environmental Policy Act (NEPA). Through the NEPA process, Basin Electric encourages state, federal and public participation in proposed projects so that once potential impact issues are identified appropriate mitigation measures can be formulated with the assistance of the participants to minimize potential impacts. An Environmental Assessment is developed which includes a comprehensive discussion and evaluation of environmental issues and serves as a baseline document for subsequent environmental regulatory permits and a federal Environmental Impact Statement when required. The goal of this process is to select a facility location that best minimizes environmental, cultural and socio-economic impacts and engineering and construction costs.

Basin Electric adheres to the appropriate North Dakota statutes regulating industrial development projects such as electrical generating facilities and high voltage transmission lines and substations. In addition, it is Basin Electric's practice to inform affected state and federal agencies when prospective projects are identified to solicit their input early in the planning process.

Clean air and clean water are important to our environment and future generations. Our region continues to rank as one of the areas with the cleanest air

in the nation, and almost all of our generation resources were built with best available pollution control technologies at the time of their construction. Our generation resources have long histories of compliance with environmental standards. As this history demonstrates, our commitment to the environment and environmental compliance remains strong and is a core value of our cooperative.

Recent environmental projects at our main baseload generation facilities are discussed below followed by details of recent EPA rulemakings affecting integrated resource planning. The recent projects at our baseload generation facilities were initiated in response to EPA rulemakings. Basin Electric and subsidiaries have been proactive in meeting these new federal emissions standards ahead of schedule. Through year-end 2023, Basin Electric had invested $2.04 billion in environmental control technology. Approximately $202 million was invested in the operation and maintenance of those controls in 2023.

The following projects have been undertaken at our majority-owned coal-based facilities to ensure compliance with federal standards. It is important to note that all of Basin Electric facilities are in full compliance with all federal and state environmental standards and permits.

- Leland Olds Station: The first round of EPA's Regional Haze Rule required greater emission control through the installation of Best Available Retrofit Technology, or BART at Leland Olds. To achieve this, Basin Electric installed wet limestone scrubbers in both units to control sulfur dioxide (SO_2) emissions. Unit 2's scrubber was commissioned in 2012; Unit 1's was commissioned in 2013. For nitrogen oxide (NO_x) control, BART required the installation of Selective Non-Catalytic Reduction (SNCR) technology on both units that were put into service in April of 2017. The BART compliance requirements were effective April 2017. Over-fire air combustion control has also been incorporated into both units at the Leland Olds. This technology introduces air high in the boiler, which reduces combustion temperatures. Since formation of NO_x is in large part a function of temperature and oxygen availability, over-fire air technology reduces these emissions. A refined coal process had also been installed on both units to help with mercury and NO_x reduction. However, this system has since been removed. A post-combustion sorbent injection system to provide additional mercury control was put in place in 2015. EPA finalized the original Effluent Limitations Guidelines (ELG) rule on September 30, 2015. The ELG rule sets limits for seven types of wastewater generated from power plants including a zero-discharge limit on bottoms ash transport water (BATW). As a result of this rule, a submerged flight conveyor system that recycles BATW has been installed at Leland Olds. The 2015 Coal Combustion Residual Rule (CCR Rule) mandated the closure of unlined surface impoundments upon a specified triggering event. An update to this rule was finalized in 2020 and again in 2024. The actions Leland Olds took to comply with the ELG rule also brought the facility into compliance with the 2015 and 2020 CCR Rules.

- Laramie River Station: Over-fire air combustion control technology was incorporated into all three units at the Laramie River Station in 2009, 2010, and 2011 to aid in the reduction of NO_x emissions. Low-NO_x burners were incorporated into all three units at the Laramie River Station between 2012, 2013, and 2014. Laramie River is also an affected BART facility which required

additional NO_x controls to be installed at the Laramie River. A Selective Catalytic Reduction (SCR) system was installed on Unit 1 in 2019 and SNCRs on Units 2 and 3 in 2018. A refined coal process had also been installed in all three units at Laramie River to help with mercury and NO_x reduction. However, this system has since been removed. A post-combustion mercury emission control system which injects activated carbon or another reagent was also installed on all units in 2015. Basin Electric is in the process of implementing a long-term compliance plan to comply with the 2015 and 2020 CCR Rules at Laramie River. Compliance will consist of closing two and retrofitting three surface impoundments in accordance with deadlines promulgated by EPA.

- Antelope Valley Station: Designed to be environmentally sound, over $400 million have been invested in capital pollution control asset investments for Antelope Valley to date. The startup fuel has been switched from fuel oil to natural gas for both units. Under Further Reasonable Progress in the State of North Dakota's Regional Haze State Implementation Plan, Antelope Valley was required to install advanced overfire air technology and low-NO_x burners for enhanced control of NO_x. Unit 1 was retrofitted in the spring of 2014 and Unit 2 in the spring of 2016. For SO_2 removal, the capacity of the lime slaking system for the Antelope Valley Station's dry scrubbers was enhanced. The dry scrubber utilizes a lime-based slurry to remove up to 90% SO_2 emissions from flue gas as it passes through the dry scrubbers. The additional slaking capacity allows for more lime to be available should high sulfur lignite coal be burned. A refined coal process had also been installed in both units to help with mercury and NO_x reduction. However, this system has since been removed. A post-combustion mercury emission control system has been installed at both units. Fabric filter bag houses capture and remove up to 99% of particulate matter. Each bag house contains more than 8,000, 35-foot-tall bags. Antelope Valley is a "zero-discharge" facility; even water is used efficiently only leaving the plant site through evaporation.

In April 2024 EPA finalized three major rulemakings that will have significant impacts on Basin Electric's existing coal fleet and future natural gas units. These rules are discussed below:

Greenhouse Gas Rule: The EPA finalized a new rule to regulate greenhouse gas (GHG) emissions from power plants, specifically carbon dioxide (CO_2). In general, the rule set the Best System of Emission Reduction (BSER) for existing coal-fired units and new natural gas fired turbines. In the final rule EPA determines that carbon capture and sequestration (CCS) with 90% capture of CO_2 is adequately demonstrated and cost reasonable for and considers it to be BSER.

For existing coal-fired steam generating units, EPA has finalized different levels of BSER depending upon how long the until will continue to operate. For units that have a federally enforceable commitment to cease operations prior to January 1, 2032, the units are exempt from the final rule. Units that operate on or after January 1, 2032, and cease operation before January 1, 2039, are considered medium-term coal units. For medium-term units, EPA has determined that BSER is co-firing 40% natural gas by 2030. Units that are planned to operate on or after January 1, 2039, are considered long-term coal units. EPA has determined that 90% CCS is BSER.

EPA breaks new and reconstructed fossil fuel-fired combustion turbines into three subcategories: low load, intermediate and baseload. Units in the low load subcategory are required to operate less than 20% of the time and use lower-emission fuels (natural gas and distillate oil). Intermediate load CTs are those that have a capacity factor greater than or equal to 20% and less than 40% based on percent of potential electric sales. Intermediate units are highly efficient simple cycle or combined cycle technology and must meet a CO_2 emission rate of 1,170 lb CO_2/MWH-g. Base load units are those with a capacity factor greater than 40%. For these units, BSER is highly efficient combined cycle technology upon startup with an emission rate of 800-900 lb CO_2/MWh-g and 90% CCS by January 1, 2032, and meeting an emission rate of 100 lb CO_2/MWh-g.

EPA plans to issue a GHG rule for existing gas units in the near future.

Mercury and Air Toxics Standards (MATS): The final rule revises the existing EGU MATS rule as part of the Clean Air Act mandated risk and technology review (RTR). The final MATS rule does the following:

- Lowers the filterable particulate matter (fPM) from 0.030 lb/MMBtu to 0.010 lb/MMBtu;
- Eliminates the mercury subcategory from lignite units thereby lowering the mercury emission limit for those units from 4.0 lb/TBtu to 1.2 lb/TBtu; and
- Requires the use of PM continuous emission monitoring systems (CEMS) to demonstrate compliance with the fPM standard.

CCR Legacy Rule: The final rule revises and contains additional requirements for CCR facilities. The final CCR Legacy Rule does the following:

- Establishes requirements for legacy CCR surface impoundments;
- Establishes definition, applicability and requirements for new term, Coal Combustion Residuals Management Units (CCRMUs)
- Limits the use of CCR for beneficial use on facility site.

SECTION L: PROJECTED DEMAND FOR SERVICES

Exhibit 2 represents Basin Electric's sales to its Class A and D members. This exhibit represents Basin Electric's supplemental power supply responsibilities to its members. As a supplemental power supplier, Basin Electric is responsible for providing the members requirements in excess of the fixed amount of power they receive from WAPA and other sources.

An econometric based load forecast was completed in early 2024. The econometric forecasting system in the load forecast is a bottom-up process that begins by developing econometric equations and forecasts for each distribution cooperative. The total system consists of approximately 350 forecasting equations and over 700 explanatory variables. Annual and monthly forecasts of energy and demand are conducted for a 30-plus year period. The distribution cooperative forecasts are combined to obtain the generation and transmission cooperative forecasts (G&T's). The G&T's power requirements are then separated into various power supply responsibilities. The Basin Electric components are combined to obtain the Basin Electric total power supply responsibility.

The modeling and forecasting are performed at Basin Electric. Throughout the

modeling and forecasting process there is constant communication and review by our member systems. Historical energy data is combined with external data obtained from government and private sector sources as well as membership consultation to form econometric forecasting equations. External projections of explanatory economic and demographic variables used in the forecasting process are obtained from the Food and Agricultural Policy Research Institute at the University of Missouri-Columbia, Missouri.; Woods & Poole Economics, Inc.; IHS Markit, the US Department of Energy, Washington, D.C.; along with various other sources.

Basin Electric's service area is electrically divided into four assessment areas across two electrical interconnections. The majority of Basin Electric's system resides in the eastern interconnection consisting of the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) assessment areas. In the western interconnection Basin Electric's system resides in the Northwest Power Pool (NWPP) and the Rocky Mountain Power Area (RMPA) assessment areas, which can be further broken down into the WAPA Upper Great Plains West (WAUW) and NorthWestern Energy (NWMT) Balancing Authority Area's (BAA) in the NWPP area and the WAPA Colorado-Missouri (WACM) and Pacificorp East (PACE) BAA's in the RMPA. These interconnections are separated by the east-west ties, which are boundaries that separate two major electrical regions of the United States. This boundary essentially runs south from Fort Peck, Montana, approximately following the South Dakota-Wyoming, Nebraska- Wyoming, and Colorado-Kansas borders. As a result of this, Basin Electric must supply generating capacity and energy on both sides of the ties to serve its member-load requirements across all four assessment areas.

The resources available to Basin Electric to serve its members' east-side requirements in SPP and MISO are as follows:

Leland Olds Station: Leland Olds Unit 1 was placed in-service on January 9, 1966, and is a base-load coal fueled unit located near Stanton, North Dakota with a net capacity of 220 MW. Leland Olds Unit 2 is a coal fueled unit that was placed in-service on December 15, 1975, and its net capacity is rated at 440 MW.

Antelope Valley Station: Basin Electric operates two 450 MW (net) thermal-generating base-load coal fired units near Beulah, North Dakota. Unit 1 began commercial operation on July 1, 1984, and Unit 2 began partial commercial operation on June 1, 1986.

Laramie River Station: Basin Electric, together with five other consumer-owned power supply entities, began construction of the Laramie River Station near Wheatland in southeast Wyoming in July 1976. The station's three units became fully operational on November 1, 1982, with each unit at a net capacity of 570 MW until the Selective Catalytic Reduction (SCR) pollution control equipment was commissioned on unit 1 in 2019 causing additional parasitic load to reduce unit 1's net capacity down to 560 MW. Basin Electric, as Project Manager and Operating Agent for the Missouri Basin Power Project, was assigned overall responsibility for the design, construction and operation of the power plant and related transmission. Units 2 and 3 of the Laramie River Station are electrically connected to the western system; Unit 1 is electrically connected to the eastern system. In

2018, Heartland Consumer Power District sold their share of the Laramie River Station to Tri-State G&T, and in 2021 Wyoming Municipal Power Agency sold their share to Tri-State because they became an All-Requirements member of Basin Electric. So today there are only 3 other owners of the Laramie River Station besides Basin Electric. The amount of power Basin Electric receives from the eastern unit is 92 MW (net).

Spirit Mound Station: Basin Electric placed in service two fuel oil-fired combustion turbines on June 30, 1978. The combined net winter rating of the two units is 120 MW and the net summer rating is 95 MW. The capacity is intended to be used primarily as reserves or replacement during initial outages of base-load units or during peak load periods when existing base-load units cannot meet the demand. The Spirit Mound Station is located near Vermillion, South Dakota.

Earl F. Wisdom Unit 1: Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 38 MW of uncommitted capacity and associated energy from the Earl F. Wisdom Unit 1. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. In accordance with the Utility Mercury and Air Toxics Standards (MATS), Unit 1 stopped burning coal in January of 2014. Corn Belt and Basin Electric completed a retrofit of Unit 1 to switch from coal to natural gas for fuel. This retrofit was completed in June of 2014.

Earl F. Wisdom Unit 2: Basin Electric partnered with Corn Belt Power Cooperative to build the 80 MW natural gas peaking unit near Spencer, Iowa. Basin Electric owns one half of the unit, which was placed in service in April 2004. Basin Electric purchases 87.5 % of Corn Belt's owned half in response to Corn Belt entering into

a Wholesale Power Contract; therefore, Basin Electric has 93.75% or 75 MW from the 80 MW combustion turbine.

Groton Generation Station: The Groton Station is located near Groton, South Dakota. Basin Electric commissioned Groton Unit 1 in 2006 and Unit 2 in 2008. These LMS 100 natural gas units provide peaking power. Unit 1 has a net winter rating of 95 MW and Unit 2 has a net winter rating of 93 MW. Unit 1 has a synchronous clutch installed to provide grid voltage stability.

Culbertson Generation Station: The Culbertson Station is located near Culbertson, Montana. Basin Electric commissioned Culbertson Unit 1 in 2010. The LMS 100 natural gas unit provides peaking power. The unit has a net winter rating of 95 MW.

Deer Creek Station: The Deer Creek Station is located near Brookings, South Dakota. Basin Electric commissioned the Deer Creek Station in August of 2012. The unit is a combined cycle natural gas facility that provides intermediate power. The unit has a net winter rating of 297 MW.

Pioneer Generation Station: The Pioneer Station northwest of Williston, North Dakota was built to serve the increasing demand for electricity by member cooperatives in northwest North Dakota. Unit 1 started commercial operation in 2013, Unit 2 and Unit 3 started commercial operation in 2014, and the twelve natural gas reciprocating internal combustion engines (RICE) referred to as units 11 through 22 started commercial operation in 2017. Each of the first three units has 45 MW of net generating capability and the twelve RICE units have a net generating capability of 8.9 MW each giving the station a total rating of approximately 242 MW. Unit 1 of Pioneer Generation Station features a clutch that allows the turbine to uncouple from the generator, allowing the generator to provide transmission system voltage support. This feature, if needed, is used to provide fast-acting reactive power which will stabilize the transmission system in the area. Phase IV of Pioneer Generation Station commenced September 2023, constructing an additional eight units. Units 4 and 5 are F-class simple cycle CTs with a net generating capability projected to be 240 MW each. The additional RICE units, Units 31-36, are projected to have a net generating capability of 18.3 MW each. Commercial operation for this additional 583 MW of generation is expected in 2025.

Lonesome Creek Station: The Lonesome Creek Station is located near Watford City, North Dakota. Commercial operation for Lonesome Creek Unit 1 began in December 2013, Units 2 and 3 in January 2015, Units 4 and 5 in March 2017, and Unit 6 in October 2021. Each unit consists of a LM 6000 natural gas combustion turbine and provides peaking power. Each unit has a net winter rating of 45 MW for a total station generating capability of 270MW. Unit 1 has a synchronous clutch installed to provide grid voltage stability.

Minot Wind Project: Basin Electric, in partnership with Central Power Electric Cooperative, has constructed a wind energy project 14 miles south of Minot, North Dakota. The first two turbines totaling 2.6 MW of generating capability were placed into commercial service in February 2002, and were recently decommissioned in March of 2022. Three additional turbines totaling 4.5 MW of generating capability were added in December 2009. The energy is delivered to members as part of Basin Electric's overall power supply.

PrairieWinds 1: Basin Electric has constructed a wind energy project of 77 turbines near Minot, North Dakota. The project has a generating capability of 115.5 MW and was placed into commercial service in December 2009.

Crow Lake Wind Project: Basin Electric has constructed a wind energy project of 108 turbines near White Lake, South Dakota. The project has a generating capability of 172 MW and was placed into commercial service in 2011. Basin Electric owns 107 turbines or approximately 170.4 MW. Basin Electric has a purchase power contract with Mitchell Technical Institute for the power out of the last turbine.

WAPA Peaking Capacity: In 1968 Basin Electric executed a long-term contract with the federal government for USBR (now WAPA) hydro peaking from the dams in the Missouri River Basin. This contract currently provides Basin Electric with 268.2 MW of winter peaking capacity at load and for Basin Electric to return a like amount of energy to Western during off-peak periods.

George Neal IV: Basin Electric and Northwest Iowa Power Cooperative (NIPCO), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that NIPCO will sell to Basin Electric NIPCO's 31 MW of uncommitted capacity and associated energy from Unit No. 4 of the George Neal Generating Station (Neal IV). In return NIPCO entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to NIPCO all of NIPCO's capacity and energy requirements in excess of the power and energy available to NIPCO from the Western Area Power Administration.

Basin Electric and Corn Belt Power Cooperative, one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt Power will sell to Basin Electric Corn Belt Power's 73 MW of uncommitted capacity and associated energy from Unit No. 4 of the George Neal Generating Station (Neal IV). In return, Corn Belt Power entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt Power all of Corn Belt Power's capacity and energy requirements in excess of the power and energy available to Corn Belt Power from the Western Area Power Administration.

Walter Scott 3 and 4: Basin Electric and Corn Belt Power, one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt Power will sell to Basin Electric Corn Belt Power's 26 MW of uncommitted capacity and associated energy from Unit No. 3 and 45 MW of uncommitted capacity and associated energy from Unit No. 4 of the Walter Scott Energy Center. In return, Corn Belt Power entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt Power all of Corn Belt Power's capacity and energy requirements in excess of the power and energy available to Corn Belt Power from the Western Area Power Administration.

Western Native American Purchase: Basin Electric receives a Native American Allocation of 39.9 MW in the winter and 41.1 MW in the summer season. This allocation is a result of congressional action that made federal power available to the Native Americans.

Rapid City DC Tie: Basin Electric and Black Hills Power, Inc. have jointly constructed a 200 MW asynchronous tie at Rapid City, South Dakota. This tie enables Basin Electric to serve load located on eastern system using capacity and/or energy from west side resources and vice versa. The Basin Electric ownership percentage is 65% and the Black Hills Power, Inc. ownership percentage is 35%. Currently, Basin Electric has rights to 130 MW of the tie.

Stegall (David Hamil) DC Tie: Tri-State G&T Association constructed a 110 MW asynchronous tie at Stegall, Nebraska. Basin Electric has acquired all rights to this tie via a lease agreement. This enables Basin Electric to serve load located on the eastern system using capacity and/or energy from west side resources and vice versa.

Sidney DC Tie: Western Area Power Administration constructed a 200 MW asynchronous tie at Sidney, Nebraska. Basin Electric has acquired 50 MW of west

to east rights to this tie. This enables Basin Electric to serve load located on the eastern system using capacity and/or energy from west side resources.

Other Short-Term Resources: Basin Electric has also entered into a number of short-term purchase agreements to meet contractual power supply obligations. Due to the relatively short duration of these arrangements no specifics are provided.

Long-Term Resource:

- Wind Purchases:
  - 40 MW west of Edgeley, North Dakota
  - Two 49.5 MW projects near Wilton, North Dakota
  - 100 MW near Baldwin, North Dakota
  - 40 MW near Highmore, South Dakota
  - 94 MW near Pollock, South Dakota
  - 99 MW near Groton, South Dakota
  - 104 MW near Hebron, North Dakota
  - 150 MW near Tioga, North Dakota
  - Two 150 MW projects near New England, North Dakota
  - 197.9 MW near Columbus, North Dakota
  - 208 MW near Avon, South Dakota
  - 142 MW near Tioga, North Dakota
  - 200 MW near Harold, South Dakota

- Solar Purchases:
  - 114 MW near Rapid City, South Dakota (COD milestone: 3/28/24)
  - 20 MW near Rapid City, South Dakota (COD milestone: 12/31/2024)

- Peaking Purchases:
  - 10 MW City of Madison, South Dakota diesel generators
  - Eight 5.5 MW waste heat recovery units from Ormat Technologies Inc. (3 sites in North Dakota near St. Anthony, Killdeer, and Zeeland; 3 in South Dakota; 1 in Montana; 1 in Minnesota)
  - One 1.7 MW waste heat/steam letdown generator and 14.5 MW combined heat and power generator from Siouxland Energy Cooperative near Sioux Center, Iowa
  - 94.2 MW in purchases from Corn Belt Power
    - 23.8 MW from Webster City, Iowa
    - 11.1 MW from Estherville, Iowa
    - 10 MW from Spencer, Iowa
    - 42 MW from their share of the Superior, Lakota, and Crosswinds wind projects in Iowa
  - ~80 MW from North Iowa Municipal Electric Cooperative Association's (NIMECA's) surplus capacity resources in Iowa
  - 15.4 MW from Pine Lake ethanol production facility near Steamboat Rock, IA
  - 6 MW from Blue Flint ethanol production facility near Underwood, ND

- Other Long Term PPAs:
  - Tolling Agreement
    - 245-262 MW from LSP Cottage Grove (12/2027-5/2043)
  - Capacity Only
    - 75-125 MW from Minnesota Power (6/2022-5/2025)
    - 100 MW from Minnesota Power (6/2025-5/2028)
    - 50-80 MW from Manitoba Hydro (6/2023-5/2028)
    - 75 MW from Dairyland Power Cooperative (6/2023-5/2033)
    - 35-185 MW from Missouri River Energy Services (10/2020-9/2035)
    - 75 MW from NRG Power Marketing (6/2023-5/2025)
    - 101-151 MW from Evergy/Dogwood Energy Facility (6/2021-5/2024)
    - 125 MW from The Energy Authority/Sheldon & Hallam Stations (6/2023-5/2026)
    - 25-50 MW from Rainbow Energy Center (6/2023-5/2027)
    - ~50 MW from National Grid for Crocker Wind accredited capacity (6/2023-5/2031)

Future Power Supply: For discussion of future power supply, please refer to Section B (Energy Conversion Facilities Under Construction) and Section D (Proposed Energy Conversion Facilities During the Next Ten-Year Time Period).

The resources available to Basin Electric to serve its members' west-side requirements are as follows:

Laramie River Station: The Laramie River Station capacity that Basin Electric receives from Units 2 and 3 on the west is 627 MW (net).

Miles City DC Tie: Basin Electric and the Western Area Power Administration have jointly constructed a 200 MW back-to-back, AC-DC-AC tie built at Miles City, Montana. This tie, which provides a 40% capacity entitlement, enables Basin Electric to serve Central Montana Electric Power Cooperative Inc., a Class A member with electrical loads located primarily west of the east-west ties, using capacity from east-side resources such as the Antelope Valley Station.

Wyoming Distributed Generation: The Wyoming Distributed Generation originally consisted of 9 peaking units located at three sites; Arvada, Hartzog and Barber Creek. One of the units at the Arvada site was retired in late 2021, so now there are 8 units across the three sites. These units are natural gas fired combustion turbines each with a net generating capability of 5 MW in the summer and 6 MW in the winter, for a total net generating capability of 40 MW summer and 48 MW winter. These units were released for commercial operation in 2002. These units currently are utilized for meeting our operating reserves for Basin Electric's west side electrical requirements.

Dry Fork Station: Basin Electric, together with the Wyoming Municipal Power Agency (WMPA) began construction of the Dry Fork Station near Gillette in northeast Wyoming in 2007. The station's single unit has a total net generating capability of 405 MW and became fully operational in November of 2011. Basin Electric owned 92.9% of the station until WMPA became a member of Basin

Electric in late 2020 and sold their share of Dry Fork in early 2021 so that Basin Electric now owns 100% of the station.

Long Term PPAs: Basin Electric has secured the following purchases for Firm Capacity and/or Firm Energy in the NWPP region.

- 50-75 MW from MacQuarie Energy (formerly "Cargill"; 5/2020-12/2025)
- 100-150 MW from Morgan Stanley Capital Group (1/2019-12/2027)

The load values contained in Exhibit 2 were obtained from the econometric based load forecast. Loads in North Dakota are located in SPP and MISO Local Resource Zone 1 assessment areas so Basin Electric's loads in each of these areas have been adjusted to an at-generator system coincident basis by allowing for reserves, on-peak losses and system diversity as outlined in Exhibit 3.

1. Basin Electric has no concentrated load centers due to the regional and rural nature of the total load. The fuel sources and transportation facilities for existing and future plants are as follows:

Plant	Fuel Source	Transportation
Leland Olds Station	Lignite Coal	Rail
Spirit Mound Station	Oil	Pipeline
Laramie River Station	Sub-Bituminous Coal	Rail
Antelope Valley Station	Lignite Coal	Mine Mouth
Minot Wind Project	Wind	N/A
WY Distributed Generation	Natural Gas	Pipeline
Wisdom Unit 2	Natural Gas/Fuel Oil	Pipeline
Groton Generation Station	Natural Gas	Pipeline
PrairieWinds 1	Wind	N/A
Crow Lake Wind Project	Wind	N/A
Culbertson Gen Station	Natural Gas	Pipeline
Deer Creek Station	Natural Gas	Pipeline
Dry Fork Station	Sub-Bituminous Coal	Mine Mouth
Pioneer Gen Station	Natural Gas	Pipeline
Lonesome Creek Station	Natural Gas	Pipeline

2. Pursuant to federal and state laws, Basin Electric will examine all alternatives capable of producing an adequate and reliable source of energy for its cooperative. Specific alternatives selected will be evaluated considering environmental, engineering and economic factors. Additional facilities, transmission and generation will be designed and operated in accordance with state and federal standards.

EXHIBIT 1 - US DEPARTMENT OF ENERGY FORM EIA-923

(distributed only to the Public Service Commission)

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 pla	☐ Yes ☒ No
Enter the total plant efficiency of the combined heat and power p	☐ %

Survey Contact

Contact	Erin Dukart			Submit Date	20-MAR-23
Title	Environmental Compliance Coordinator				
Address	1717 E. Interstate Avenue				
City/State/Zip	Bismarck	ND 58503			
Email	edukart@bepc.com	Phone	(701) 557-5557	Fax	

Supervisor of Contact Person for Survey

Contact	Colleen Peterson				
Title					
Address					
City/State/Zip					
Email	cpeterson@bepc.com	Phone	(701) 516-2719	Fax	

Report For

Company Name	Basin Electric Power Coop				
Plant Name	Leland Olds				
Plant ID	2817	Plant County	Mercer		
Plant Address	Hwy 200				
Plant City	Stanton			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)

(2) Other Incoming Electricity

(3) Total Sources (1 + 2)

(4) Station Use

(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

(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 elecytic 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. ANNUAL ENVIRONMENTAL INFORMATION

SCHEDULE 8. PART A. ANNUAL BYPRODUCT DISPOSITION

Complete an individual Schedule 8. Part A annually for each organic-fueled thermoelectric power plant (i.e., steam-electric plants, including nuclear and combined cycle plants with a total steam turbine capacity of greater than, or equal to 100 megawatts.
- Enter the quantity of combustion by-products for the year, by type of disposal.
- If actual data are not available, provide an estimate value.
- Report the quantity of combustion by-products rounded to the nearest 0.1 thousand tons.
- Report sales of steam in million BTU (MMBtu)
- If no by-product was produced, place a check in the checkbox labeled "Select if no combustion by-product were produced"

NOTE: PCD = Particulate Control Device; FGD = Flue Gas Desulfurization; FBC = Fluidized Bed combustion; IGCC = Integrated Gasification Combined Cycle

☐ No Byproducts

	Disposal			Beneficial Use		Storage		
Combustion Byproduct	On-site Landfill	Disposal On-site Ponds	Disposal Off-site	Sold	Used On-site	Used Off-site	Storage Stored On-site	Stored Off-site	Total
Fly ash from standard boiler/PCD units			110.2	3.1					113.3
Fly ash from units with dry FGD									
Fly ash from FBC units									
Bottom ash from standard boiler units			48.0	45.3					93.3
Bottom (bed) ash from FBC units									
FGD Gypsum			157.3	4.0					161.3
Other FGD byproducts									
Ash from coal gasification (IGCC) units									
Other (specify via footnote on Schedule 9)									
Steam Sales (MMBtu)									

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

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermolectric 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	437	934	1,517			2,888
Disposal						
Other						

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				

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	12	252	0	9	0	273

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

Report electricity generation related operational emissions data for sulfur dioxide (SO2), nitrogen oxides (NO2), particulate matter, mercury, and acid gas.

Annual Operations

Environmental Equipment and/or Technology Type							NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
ypes	PM Control ID	SO2 CONTOL ID	NOX Control ID	Mercury Control	Status	Hours in Service	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)	Removal Efficiency (nearest 0.1% by weight)
CI				1	OP	7882												90.1	2.28	
N			1		OP	7882	.13	.1348												
V			1		OP	7882	.13	.1348												
CI				2	OP	8103												90	3.07	
V			2		OP	8103	.2955	.2959												
K	1			1B	OP	7882			.006	80	99.8	12-1974						90	2.28	
K	2			2B	OP	8103			.0054	81	99.5	12-1976						90	3.07	
N			1		OP	7882	.13	.1348												
N			2		OP	8103	.2955	.2959												
P		1		1C	OP	7882							78	97.7	08-2013	31.4	39685	90.1	2.28	

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

Annual Operations

Environmental Equipment and/or Technology Type						NOx Emission Rate (lbs/MMBtu)	Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
ypes	PM Control ID	SO2 CONTOL ID	NOX Control ID	Mercury Control	Status Hours in Service	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)	Removal Efficiency (nearest 0.1% by weight)
P		2		2C	OP 8103						80	98.7	01-2013	59.4	84306	90.1	3.07	

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
1	$222	$283	$723		$1,228
2	$215	$651	$794		$1,660

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 seperate schedule for each reporting month.

Complete a seperate 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	Hours in 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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumptio
Report Month 1																		
	ON	OP	744	0		71933	71933	0	4	38	43	54	73	1		3211.104	3211.104	
Report Month 2																		
	ON	OP	672	0		67375	67375	0	4	39	45	52	78	1		2716.559	2716.559	0
Report Month 3																		
	ON	OP	744	0		68469	68469	0	4	41	47	48	66	1		3056.452	3056.452	0
Report Month 4																		
	ON	OP	720	0		70466	70466	0	4	42	48	53	69	1		3044.114	3044.114	0
Report Month 5																		
	ON	OP	744	0		72610	72610	0	4	47	53	65	82	1		3241.303	3241.303	0
Report Month 6																		
	ON	OP	720	0		72121	72121	0	4	55	63	70	88	1		3115.623	3115.623	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 seperate schedule for each reporting month.

Complete a seperate 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	Hours in 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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 7																		
	ON	OP	744	0		72208	72208	0	4	61	65	81	91	1		3223.378	3223.378	0
Report Month 8																		
	ON	OP	744	0		69830	69830	0	4	61	67	84	93	1		3117.215	3117.215	0
Report Month 9																		
	ON	OP	720	0		71722	71722	0	4	63	66	80	92	1		3098.399	3098.399	0
Report Month 10																		
	ON	OP	744	0		68231	68231	0	4	59	64	75	90	1		3045.821	3045.821	0
Report Month 11																		
	ON	OP	720	0		70201	70201	0	4	49	56	62	81	1		3032.681	3032.681	0
Report Month 12																		
	ON	OP	744	0		73454	73454	0	4	39	46	54	67	1		3278.968	3278.968	0

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

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;ooling ystem ID	Cooling System Type	Cooling System Status	Hours in Service Per monthe	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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumptio
.eport Month 1																		
	ON	OP	744	0		143867	143867	0	4	38	43	58	70	1		6422.208	6422.208	
.eport Month 2																		
	ON	OP	672	0		134750	134750	0	4	39	45	64	79	1		5433.119	5433.119	0
.eport Month 3																		
	ON	OP	744	0		136938	136938	0	4	41	47	61	83	1		6112.904	6112.904	0
.eport Month 4																		
	ON	OP	720	0		140931	140931	0	4	42	48	55	77	1		6088.229	6088.229	0
.eport Month 5																		
	ON	OP	744	0		145220	145220	0	4	47	53	68	80	1		6482.606	6482.606	0
.eport Month 6																		
	ON	OP	720	0		144242	144242	0	4	55	63	76	91	1		6231.247	6231.247	0

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

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Cooling System ID	Cooling System Type	Cooling System Status	Hours in 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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 7																		
	ON	OP	744	0		144417	144417	0	4	61	65	86	94	1		6446.756	6446.756	0
Report Month 8																		
	ON	OP	744	0		139660	139660	0	4	61	67	87	96	1		6234.43	6234.43	0
Report Month 9																		
	ON	OP	720	0		109979	109979	0	4	63	66	82	96	1		4751.097	4751.097	0
Report Month 10																		
	ON	OP	744	0		136462	136462	0	4	59	64	78	91	1		6091.643	6091.643	0
Report Month 11																		
	ON	OP	720	0		140402	140402	0	4	49	56	70	86	1		6065.363	6056.363	0
Report Month 12																		
	ON	OP	744	0		146907	146907	0	4	39	46	65	77	1		6557.936	6557.936	0

SCHEDULE 9. COMMENTS

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

Schedule	Part	Item	Comments

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		1C/SP			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While emission control equipment does provide some acid gas removal, the amount is unknown.
		8C		2/SP			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.		The entered value is between 50% and 99%. Please check the software checks.
		8C		2C/SP			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While emission control equipment does provide some acid gas removal, the amount is unknown.

U.S. Department of Energy
Energy Information Administration
Form EIA-923

Supplemental EIA923 Power Plant Operations Report

Year: **2023** Plant: **2817** **Leland Olds**

OMB No. 1905-0129
Approval Expires 05/31/2023

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 pla	☐ **Yes** ☒ **No**
Enter the total plant efficiency of the combined heat and power p	☐ **%**

Survey Contact

Contact	Erin Dukart			Submit Date	25-MAR-24
Title	Environmental Compliance Coordinator				
Address	1717 E. Interstate Avenue				
City/State/Zip	Bismarck		ND 58503		
Email	edukart@bepc.com		Phone	(701) 557-5557	Fax

Supervisor of Contact Person for Survey

Contact	Colleen Peterson				
Title					
Address					
City/State/Zip					
Email	cpeterson@bepc.com		Phone	(701) 516-2719	Fax

Report For

Company Name	Basin Electric Power Coop		
Plant Name	Leland Olds		
Plant ID	2817	Plant County	Mercer
Plant Address	Hwy 200		
Plant City	Stanton	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)

(2) Other Incoming Electricity

(3) Total Sources (1 + 2)

(4) Station Use

(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

(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 elecytic 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. ANNUAL ENVIRONMENTAL INFORMATION

SCHEDULE 8. PART A. ANNUAL BYPRODUCT DISPOSITION

Complete an individual Schedule 8. Part A annually for each organic-fueled thermoelectric power plant (i.e., steam-electric plants, including nuclear and combined cycle plants with a total steam turbine capacity of greater than, or equal to 100 megawatts.
- Enter the quantity of combustion by-products for the year, by type of disposal.
- If actual data are not available, provide an estimate value.
- Report the quantity of combustion by-products rounded to the nearest 0.1 thousand tons.
- Report sales of steam in million BTU (MMBtu)
- If no by-product was produced, place a check in the checkbox labeled "Select if no combustion by-product were produced"

NOTE: PCD = Particulate Control Device; FGD = Flue Gas Desulfurization; FBC = Fluidized Bed combustion; IGCC = Integrated Gasification Combined Cycle

☐ No Byproducts

	Disposal			Beneficial Use		Storage		
Combustion Byproduct	On-site Landfill	Disposal On-site Ponds	Disposal Off-site	Sold	Used On-site	Used Off-site	Storage Stored On-site	Stored Off-site	Total
Fly ash from standard boiler/PCD units			81.2	9.8					91.0
Fly ash from units with dry FGD									
Fly ash from FBC units									
Bottom ash from standard boiler units			28.2	61.2					89.4
Bottom (bed) ash from FBC units									
FGD Gypsum			77.2	7.4					84.6
Other FGD byproducts									
Ash from coal gasification (IGCC) units									
Other (specify via footnote on Schedule 9)									
Steam Sales (MMBtu)									

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

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermolectric 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						
Disposal						
Other	373	1,973	3,812	0	0	6,158

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	747	0	4,198	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	273	439	0	23	0	735

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

Report electricity generation related operational emissions data for sulfur dioxide (SO2), nitrogen oxides (NO2), particulate matter, mercury, and acid gas.

Annual Operations

Environmental Equipment and/or Technology Type							NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
ypes	PM Control ID	SO2 CONTOL ID	NOX Control ID	Mercury Control	Status	Hours in Service	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)	Removal Efficiency (nearest 0.1% by weight)
CI				1	OP	5555												90.8	1.94	
N			1		OP	5555	.1446	.1498												
V			1		OP	5555	.1444	.1498												
CI				2	OP	7488												87.5	2.62	
V			2		OP	7488	.305	.3163												
K	1			1B	OP	5555			.0134	80	99.8	12-1974						90.8	1.94	
K	2			2B	OP	7488			.0067	81	99.5	12-1976						87.5	2.62	
N			1		OP	5555	.1446	.1498												
N			2		OP	7488	.305	.3163												
?		1		1C	OP	5555							78	97.7	08-2013	21	30700	90.8	1.94	

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

Annual Operations

Environmental Equipment and/or Technology Type						NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
ypes	PM Control ID	SO2 CONTOL ID	NOX Control ID	Mercury Control	Status	Hours in Service	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)	Removal Efficiency (nearest 0.1% by weight)
P		2		2C	OP	7488						80	98.7	01-2013	53.1	84709	87.5	2.62	

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
1	$1,256	$332	$2,060	$1	$3,649
2	$3,262	$642	$4,098	$3	$8,005

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

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Complete a seperate schedule for each reporting month.

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Cooling System ID	Cooling System Type	Cooling System Status	Hours in 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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumptio
Report Month 1																		
	ON	OP	744	0		77040	77040	0	4	38	43	54	73	1		3439.06	3439.06	0
Report Month 2																		
	ON	OP	672	0		77757	77757	0	4	38	43	54	73	1		3135.158	3135.158	
Report Month 3																		
	ON	OP	744	0		48564	48564	0	4	41	47	48	66	1		2167.895	2167.895	
Report Month 4																		
	ON	OP	720	0		34665	34665	0	4	42	48	53	69	1		1497.533	1497.533	0
Report Month 5																		
	ON	OP	744	0		38241	38241	0	4	47	53	65	82	1		1707.091	1707.091	0
Report Month 6																		
	ON	OP	720	0		39858	39858	0	4	55	63	70	88	1		1721.866	1721.866	0

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

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					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																			
	ON	OP	744	0		72879	72879	0	4	61	65	81	91	1		3253.316	3253.316	0	
Report Month 8																			
	ON	OP	744	0		73321	73321	0	4	61	67	84	93	1		3273.07	3273.07	0	
Report Month 9																			
	ON	OP	720	0		71313	71313	0	4	63	66	80	92	1		3080.739	3080.739	0	
Report Month 10																			
	ON	OP	744	0		65537	65537	0	4	59	64	75	90	1		2925.576	2925.576	0	
Report Month 11																			
	ON	OP	720	0		73822	73822	0	4	49	56	62	81	1		3189.093	3189.093	0	
Report Month 12																			
	ON	OP	744	0		74251	74251	0	4	39	46	54	67	1		3314.562	3314.562	0	

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

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					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	Consumptio
Report Month 1																		
	ON	OP	744	0		145323	145323	0	4	38	43	58	70	1		6487.199	6487.199	0
Report Month 2																		
	ON	OP	672	0		144111	144111	0	4	38	43	54	73	1		5810.569	5810.569	0
Report Month 3																		
	ON	OP	744	0		137668	137668	0	4	41	47	61	83	1		6145.52	6145.52	
Report Month 4																		
	ON	OP	720	0		136427	136427	0	4	42	48	55	77	1		5893.661	5893.661	0
Report Month 5																		
	ON	OP	744	0		136699	136699	0	4	47	53	68	80	1		6102.234	6102.234	0
Report Month 6																		
	ON	OP	720	0		136212	136212	0	4	55	63	76	91	1		5884.359	5884.359	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.

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					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																		
	ON	OP	744	0		135304	135304	0	4	61	65	86	94	1		6039.98	6039.98	0
Report Month 8																		
	ON	OP	744	0		133608	133608	0	4	61	67	87	96	1		5964.273	5964.273	0
Report Month 9																		
	ON	OP	720	0		133905	133905	0	4	63	66	82	96	1		5784.679	5784.679	0
Report Month 10																		
	ON	OP	744	0		135062	135062	0	4	59	64	78	91	1		6029.146	6029.146	0
Report Month 11																		
	ON	OP	720	0		139047	139047	0	4	49	56	70	86	1		6006.837	6006.837	0
Report Month 12																		
	ON	OP	744	0		141020	141020	0	4	39	46	65	77	1		6295.115	6295.115	0

SCHEDULE 9. COMMENTS

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

Schedule	Part	Item	Comments

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		1C/SP			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While emission control equipment does provide some acid gas removal, the amount is unknown.
		8C		2/SP			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.		The entered value is between 50% and 99%. Please check the software checks.
		8C		2C/SP			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While emission control equipment does provide some acid gas removal, the amount is unknown.

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 pla	☐ Yes ☒ No
Enter the total plant efficiency of the combined heat and power p	☐ %

Survey Contact

Contact	Erin Dukart			Submit Date	20-SEP-23
Title	Environmental Compliance Coordinator				
Address	1717 E. Interstate Avenue				
City/State/Zip	Bismarck	ND	58503		
Email	edukart@bepc.com	Phone	(701) 557-5557	Fax	

Supervisor of Contact Person for Survey

Contact	Colleen Peterson				
Title					
Address					
City/State/Zip					
Email	cpeterson@bepc.com	Phone	(701) 516-2719	Fax	

Report For

Company Name	Basin Electric Power Coop		
Plant Name	Antelope Valley		
Plant ID	6469	Plant County	Mercer
Plant Address	Hwy 200		
Plant City	Beulah	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)

(2) Other Incoming Electricity

(3) Total Sources (1 + 2)

(4) Station Use

(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

(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 elecytic 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. ANNUAL ENVIRONMENTAL INFORMATION

SCHEDULE 8. PART A. ANNUAL BYPRODUCT DISPOSITION

Complete an individual Schedule 8. Part A annually for each organic-fueled thermoelectric power plant (i.e., steam-electric plants, including nuclear and combined cycle plants with a total steam turbine capacity of greater than, or equal to 100 megawatts.
- Enter the quantity of combustion by-products for the year, by type of disposal.
- If actual data are not available, provide an estimate value.
- Report the quantity of combustion by-products rounded to the nearest 0.1 thousand tons.
- Report sales of steam in million BTU (MMBtu)
- If no by-product was produced, place a check in the checkbox labeled "Select if no combustion by-product were produced"

NOTE: PCD = Particulate Control Device; FGD = Flue Gas Desulfurization; FBC = Fluidized Bed combustion; IGCC = Integrated Gasification Combined Cycle

☐ No Byproducts

	Disposal			Beneficial Use		Storage		
Combustion Byproduct	On-site Landfill	Disposal On-site Ponds	Disposal Off-site	Sold	Used On-site	Used Off-site	Storage Stored On-site	Stored Off-site	Total
Fly ash from standard boiler/PCD units									
Fly ash from units with dry FGD			628.8	0.0		44.7			673.5
Fly ash from FBC units									0.0
Bottom ash from standard boiler units			157.2						157.2
Bottom (bed) ash from FBC units									
FGD Gypsum									
Other FGD byproducts									
Ash from coal gasification (IGCC) units									
Other (specify via footnote on Schedule 9)									
Steam Sales (MMBtu)									

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

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermolectric 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	922	1,427	1,073			3,422
Disposal						
Other						

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			537	

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						

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

Report electricity generation related operational emissions data for sulfur dioxide (SO2), nitrogen oxides (NO2), particulate matter, mercury, and acid gas.

Annual Operations

Environmental Equipment and/or Technology Type							NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
ypes	PM Control ID	SO2 CONTOL ID	NOX Control ID	Mercury Control	Status	Hours in Service	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)	Removal Efficiency (nearest 0.1% by weight)
N			B1		OP	7818	.1313	.1342												
T				1	OP	7818												85.7	3.01	
V			B1		OP	7818	.1313	.1342												
N			B2		OP	8406	.1342	.1388												
T				2	OP	8406												85.6	3.04	
V			B2		OP	8406	.1342	.1388												
R	BH1			1	OP	7818			.001	80	99.9	08-1986						85.7	3.01	
R	BH2			2	OP	8406			.0009	80	99.9	08-1983						85.6	3.04	
D		FGD1		1	OP	7818							64	86.8	08-1986	41.5	13721	85.7	3.01	
D		FGD2		2	OP	8406							86	86.8	08-1983	46	13870	85.6	3.04	

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

Annual Operations

Environmental Equipment and/or Technology Type						NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
ypes	PM Control ID	SO2 CONTOL ID	NOX Control ID	Mercury Control	Status	Hours in Service	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)	Removal Efficiency (nearest 0.1% by weight)

Flue Gas Desulfurization Unit ID	Feed Materials and Chemicals	FGD Operation and Maintenance Expenditures During Year, Excluding Electricity (Thousand Dollars)		Maintenance, Material and All Other Costs	Total
		Land and Supervision	Waste Disposal		
FGD1	$5,005	$1,221	$1,208	$28	$7,462
FGD2	$4,575	$1,221	$1,214	$27	$7,037

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

omplete 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 iegawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate 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	Hours in 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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumptio
eport Month 1																		
C1	RF	OP	743	3.392	3244	3244	0	3244	2	32				7	144.817	144.817	0	144.817
eport Month 2																		
C1	RF	OP	672	2.165	2292	2292	0	2292	2	32				7	92.429	92.429	0	92.429
eport Month 3																		
C1	RF	OP	687	2.793	2671	2671	0	2671	2	32				7	119.238	119.238	0	119.238
eport Month 4																		
C1	RF	OP	653	2.202	2177	2177	0	2177	2	40				7	94.037	94.037	0	94.037
eport Month 5																		
C1	RF	OP	651	3.066	2932	2932	0	2932	2	50				7	130.89	130.89	0	130.89
eport Month 6																		
C1	RF	OP	690	3.575	3533	3533	0	3533	2	60				7	152.655	152.655	0	152.655

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

omplete 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 ıegawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate 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	Hours in Service Per monthe	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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption
eport Month 7																		
C1	RF	OP	744	4.329	4140	4140	0	4140	2	75				7	184.843	184.843	0	184.843
eport Month 8																		
C1	RF	OP	725	4.282	4095	4095	0	4095	2	73				7	182.823	182.823	0	182.823
eport Month 9																		
C1	RF	OP	720	3.662	3619	3619	0	3619	2	63				7	156.343	156.343	0	156.343
eport Month 10																		
C1	RF	OP	598	2.935	2807	2807	0	2807	2	49				7	125.3	125.3	0	125.3
eport Month 11																		
C1	RF	OP	720	3.07	3034	3034	0	3034	2	34				7	131.088	131.088	0	131.088
eport Month 12																		
C1	RF	OP	744	3.023	2892	2892	0	2892	2	32				7	129.091	129.091	0	129.091

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 seperate schedule for each reporting month.

Complete a seperate 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	Hours in 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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 1																		
C2	RF	OP	459	2.025	1907	1907	0	1907	2	32				7	85.125	85.125	0	85.125
Report Month 2																		
C2	RF	OP	615	1.931	2013	2013	0	2013	2	32				7	81.18	81.18	0	81.18
Report Month 3																		
C2	RF	OP	714	2.77	2609	2609	0	2609	2	32				7	116.457	116.457	0	116.457
Report Month 4																		
C2	RF	OP	614	2.578	2509	2509	0	2509	2	40				7	108.41	108.41	0	108.41
Report Month 5																		
C2	RF	OP	514	2.381	2243	2243	0	2243	2	50				7	100.12	100.12	0	100.12
Report Month 6																		
C2	RF	OP	720	3.672	3573	3573	0	3573	2	60				7	154.375	154.375	0	154.375

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 seperate schedule for each reporting month.

Complete a seperate 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.

					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)			
Cooling System ID	Cooling System Type	Cooling System Status	Hours in Service Per month	Annual Amt of Chlorine added to Cooling Water (1000 lbs)	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																		
C2	RF	OP	744	4.253	4005	4005	0	4005	2	75				7	178.807	178.807	0	178.807
Report Month 8																		
C2	RF	OP	653	3.773	3554	3554	0	3554	2	73				7	158.647	158.647	0	158.647
Report Month 9																		
C2	RF	OP	720	3.596	3499	3499	0	3499	2	63				7	151.177	151.177	0	151.177
Report Month 10																		
C2	RF	OP	669	3.222	3035	3035	0	3035	2	49				7	135.47	135.47	0	135.47
Report Month 11																		
C2	RF	OP	606	2.513	2446	2446	0	2446	2	34				7	105.662	105.662	0	105.662
Report Month 12																		
C2	RF	OP	700	2.914	2744	2744	0	2744	2	32				7	122.499	122.499	0	122.499

SCHEDULE 9. COMMENTS

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

Schedule	Part	Item	Comments
8	C		Chemical injected into scrubber.
8	D	O	USGS Data from the lake.

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
		8A					808 You have entered a cost in O&M Expenditures for FGD on Schedule 8B (Part 3), but have not entered a positive quantity of FGD Gypsum or By-products in any column on Schedule 8A. Please enter the quantity of FGD byproduct or FGD Gypsum associated with the costs in Schedule 8B.		FGD quantity is included in the fly ash quantity.
		8B					835 Sales of fly and bottom ash (Line 1, 2, 3, 4, and 5) were reported on Schedule 8, Part A. Please enter the revenue (Part 13) in units of thousand dollars from those sales on Schedule 8B, if applicable. If the fly and bottom ash sold were not sold intermingled, please comment.		No sales.
		8C		1/SD			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While emission control equipment does provide some acid gas removal, the amount is unknown.
		8C		2/SD			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While emission control equipment does provide some acid gas removal, the amount is unknown.
		8C		OT			1815 A comment is required on Schedule 9 for the Other Equipment Type (OT) you selected on Schedule 8C. Please enter Schedule 8, Part C, and Item OT next to the explanation comment.		This has been done.
		8D					864 The code for "Other" was selected for the 'Measured or Estimated' Water Temperature. Specify the method in an override comment.		This has been done.

U.S. Department of Energy
Energy Information Administration
Form EIA-923

Supplemental EIA923 Power Plant Operations Report

Year: **2023** Plant: **6469** **Antelope Valley**

OMB No. 1905-0129
Approval Expires 05/31/2023

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 pla	☐ **Yes** ☒ **No**
Enter the total plant efficiency of the combined heat and power p	☐ **%**

Survey Contact

Contact	Erin Dukart			Submit Date	25-MAR-24
Title	Environmental Compliance Coordinator				
Address	1717 E. Interstate Avenue				
City/State/Zip	Bismarck	ND	58503		
Email	edukart@bepc.com	Phone	(701) 557-5557	Fax	

Supervisor of Contact Person for Survey

Contact	Colleen Peterson				
Title					
Address					
City/State/Zip					
Email	cpeterson@bepc.com	Phone	(701) 516-2719	Fax	

Report For

Company Name	Basin Electric Power Coop		
Plant Name	Antelope Valley		
Plant ID	6469	Plant County	Mercer
Plant Address	Hwy 200		
Plant City	Beulah	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)

(2) Other Incoming Electricity

(3) Total Sources (1 + 2)

(4) Station Use

(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

(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 elecytic 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. ANNUAL ENVIRONMENTAL INFORMATION

SCHEDULE 8. PART A. ANNUAL BYPRODUCT DISPOSITION

Complete an individual Schedule 8. Part A annually for each organic-fueled thermoelectric power plant (i.e., steam-electric plants, including nuclear and combined cycle plants with a total steam turbine capacity of greater than, or equal to 100 megawatts.
- Enter the quantity of combustion by-products for the year, by type of disposal.
- If actual data are not available, provide an estimate value.
- Report the quantity of combustion by-products rounded to the nearest 0.1 thousand tons.
- Report sales of steam in million BTU (MMBtu)
- If no by-product was produced, place a check in the checkbox labeled "Select if no combustion by-product were produced"

NOTE: PCD = Particulate Control Device; FGD = Flue Gas Desulfurization; FBC = Fluidized Bed combustion; IGCC = Integrated Gasification Combined Cycle

☐ No Byproducts

	Disposal			Beneficial Use		Storage		
Combustion Byproduct	On-site Landfill	Disposal On-site Ponds	Disposal Off-site	Sold	Used On-site	Used Off-site	Storage Stored On-site	Stored Off-site	Total
Fly ash from standard boiler/PCD units									
Fly ash from units with dry FGD			468.3	0.0		29.9			498.2
Fly ash from FBC units									
Bottom ash from standard boiler units			117.1						117.1
Bottom (bed) ash from FBC units									
FGD Gypsum									
Other FGD byproducts									
Ash from coal gasification (IGCC) units									
Other (specify via footnote on Schedule 9)									
Steam Sales (MMBtu)									

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

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermolectric 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						
Disposal						
Other	1,909	789	4,660	0	0	7,358

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	0	0	3,184	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	0	0	0	0	0

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

Report electricity generation related operational emissions data for sulfur dioxide (SO2), nitrogen oxides (NO2), particulate matter, mercury, and acid gas.

Annual Operations

Environmental Equipment and/or Technology Type							NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
ypes	PM Control ID	SO2 CONTOL ID	NOX Control ID	Mercury Control	Status	Hours in Service	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)	Removal Efficiency (nearest 0.1% by weight)
N			B1		OP	7325	.1329	.132												
T				1	OP	7325												85.7	3.00	
V			B1		OP	7325	.1329	.132												
N			B2		OP	6487	.1387	.1368												
T				2	OP	6487												85.6	3.03	
V			B2		OP	6487	.1357	.1368												
R	BH1			1	OP	7325			.005	80	86.8	09-1983						85.7	3.00	
R	BH2			2	OP	6487			.0064	80	99.9	08-1986						85.6	3.03	
D		FGD1		1	OP	7325							64	86.8	09-1983	33.6	12086	85.7	3.00	
D		FGD2		2	OP	6487							86	86.8	08-1986	30.4	12855	85.6	3.03	

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

Annual Operations

Environmental Equipment and/or Technology Type						NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
ypes	PM Control ID	SO2 CONTOL ID	NOX Control ID	Mercury Control	Status	Hours in Service	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)	Removal Efficiency (nearest 0.1% by weight)

Flue Gas Desulfurization Unit ID	Feed Materials and Chemicals	FGD Operation and Maintenance Expenditures During Year, Excluding Electricity (Thousand Dollars)		Maintenance, Material and All Other Costs	Total
		Land and Supervision	Waste Disposal		
FGD1	$6,062	$1,332	$1,220	$350	$8,964
FGD2	$5,609	$1,332	$6,138	$349	$13,428

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

omplete 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 egawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate 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	Hours in Service Per monthe	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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumptio
eport Month 1																		
C1	RF	OP	632	2.861	2718	2718	0	2718	2	32				7	121.335	121.335	0	121.335
eport Month 2																		
C1	RF	OP	624	2.646	2783	2783	0	2783	2	32				7	112.203	112.203	0	112.203
eport Month 3																		
C1	RF	OP	576	2.363	2244	2244	0	2244	2	32				7	100.195	100.195	0	100.195
eport Month 4																		
C1	RF	OP	645	2.389	2345	2345	0	2345	2	32				7	101.322	101.322	0	101.322
eport Month 5																		
C1	RF	OP	538	2.854	2711	2711	0	2711	2	62				7	121.02	121.02	0	121.02
eport Month 6																		
C1	RF	OP	548	3.557	3491	3491	0	3491	2	69				7	150.835	150.835	0	150.835

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

omplete 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 negawatts.

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Cooling System ID	Cooling System Type	Cooling System Status	Hours in Service Per monthe	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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption
eport Month 7																		
C1	RF	OP	673	3.776	3587	3587	0	3587	2	71				2	160.115	160.115	0	160.115
eport Month 8																		
C1	RF	OP	578	3.074	2920	2920	0	2920	2	71				7	130.344	130.344	0	130.344
eport Month 9																		
C1	RF	OP	442	2.135	2095	2095	0	2095	2	64				7	90.527	90.527	0	90.527
eport Month 10																		
C1	RF	OP	413	1.953	1855	1855	0	1855	2	49				7	82.801	82.801	0	82.801
eport Month 11																		
C1	RF	OP	710	3.284	3223	3223	0	3223	2	37				7	139.246	139.246	0	139.246
eport Month 12																		
C1	RF	OP	744	3.353	3185	3185	0	3185	2	32				7	142.17	142.17	0	142.17

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

omplete 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 egawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate 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	Hours in 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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumptio
eport Month 1																		
C2	RF	OP	744	3.412	3120	3120	0	3120	2	32				7	139.265	139.265	0	139.265
eport Month 2																		
C2	RF	OP	625	2.712	2745	2745	0	2745	2	32				7	110.687	110.687	0	110.687
eport Month 3																		
C2	RF	OP	743	3.187	2914	2914	0	2914	2	32				7	130.085	130.085	0	130.852
eport Month 4																		
C2	RF	OP	110	.383	362	362	0	362	2	32				7	15.638	15.638	0	15.638
eport Month 5																		
C2	RF	OP	0	0	0	0	0	0	2	62				7	0	0	0	0
eport Month 6																		
C2	RF	OP	154	.871	823	823	0	823	2	69				7	35.542	35.542	0	35.542

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

omplete 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 ıegawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate 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	Hours in Service Per monthe	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 Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption
eport Month 7																		
C2	RF	OP	686	3.93	3594	3594	0	3594	2	71				2	160.435	160.435	0	180.435
eport Month 8																		
C2	RF	OP	740	4.136	3781	3781	0	3781	2	71				7	168.816	168.816	0	168.816
eport Month 9																		
C2	RF	OP	632	3.063	2894	2894	0	2894	2	64				7	125.013	125.013	0	125.013
eport Month 10																		
C2	RF	OP	592	2.7	2469	2469	0	2469	2	49				7	110.209	110.209	0	110.209
eport Month 11																		
C2	RF	OP	664	3.084	2914	2914	0	2914	2	37				7	125.884	125.884	0	125.884
eport Month 12																		
C2	RF	OP	671	3.099	2833	2833	0	2833	2	32				7	126.48	126.48	0	126.48

SCHEDULE 9. COMMENTS

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

Schedule	Part	Item	Comments
8	C		Chemical injected into scrubber
8	D		USGS Data from the lake.

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
		8A					808 You have entered a cost in O&M Expenditures for FGD on Schedule 8B (Part 3), but have not entered a positive quantity of FGD Gypsum or By-products in any column on Schedule 8A. Please enter the quantity of FGD byproduct or FGD Gypsum associated with the costs in Schedule 8B.		FGDE quantity is included in the fly ash quantity.
		8C		1/SD			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While emission control equipment does provide some acid gas removal, the amount is unknown.
		8C		2/SD			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While emission control equipment does provide some acid gas removal, the amount is unknown.
		8C		OT			1815 A comment is required on Schedule 9 for the Other Equipment Type (OT) you selected on Schedule 8C. Please enter Schedule 8, Part C, and Item OT next to the explanation comment.		This has been done.
		8D					864 The code for "Other" was selected for the 'Measured or Estimated' Water Temperature. Specify the method in an override comment.		This has been done.

EXHIBIT 2 - SUMMER/WINTER LOADS BY STATE

Basin Electric Member Loads by State

Note: Historical 2000-2023 and Forecasted 2024-2034

SUMMER Peak Demand (MW)

	ND	%	SD	%	MN	%	IA	%	NE	%	MT	%	CO	%	WY	%	BEPC TOTAL
2000	293	23.0%	302	23.7%	54	4.2%	99	7.8%	215	16.9%	29	2.3%	82	6.5%	200	15.7%	1,273
2001	307	22.2%	343	24.8%	58	4.2%	116	8.4%	227	16.5%	30	2.2%	82	5.9%	218	15.8%	1,380
2002	315	21.3%	352	23.8%	58	3.9%	127	8.6%	254	17.1%	44	3.0%	95	6.4%	236	15.9%	1,480
2003	353	22.9%	346	22.4%	58	3.8%	121	7.9%	239	15.5%	56	3.6%	114	7.4%	254	16.5%	1,541
2004	329	21.2%	354	22.8%	55	3.6%	119	7.7%	233	15.0%	62	4.0%	130	8.4%	271	17.5%	1,554
2005	357	20.7%	400	23.2%	62	3.6%	131	7.6%	270	15.7%	74	4.3%	132	7.6%	296	17.2%	1,722
2006	400	20.5%	440	22.6%	71	3.7%	188	9.7%	273	14.0%	82	4.2%	134	6.9%	358	18.4%	1,947
2007	452	21.9%	461	22.3%	92	4.4%	186	9.0%	262	12.7%	86	4.2%	135	6.6%	389	18.9%	2,063
2008	465	22.5%	421	20.4%	88	4.2%	177	8.6%	270	13.1%	74	3.6%	142	6.9%	426	20.7%	2,062
2009	448	21.4%	438	20.9%	102	4.9%	201	9.6%	232	11.1%	65	3.1%	145	7.0%	400	19.1%	2,090
2010	509	20.5%	472	19.0%	181	7.3%	459	18.5%	238	9.6%	70	2.8%	145	5.9%	407	16.4%	2,482
2011	543	20.8%	548	21.0%	169	6.5%	460	17.7%	280	10.8%	69	2.7%	140	5.4%	396	15.2%	2,607
2012	693	23.1%	596	19.9%	207	6.9%	476	15.9%	333	11.1%	104	3.5%	208	6.9%	377	12.6%	2,994
2013	812	26.5%	572	18.7%	224	7.3%	460	15.0%	299	9.8%	147	4.8%	180	5.9%	370	12.1%	3,063
2014	889	29.3%	508	16.8%	160	5.3%	433	14.3%	311	10.3%	178	5.9%	179	5.9%	372	12.3%	3,029
2015	1,187	34.7%	587	17.2%	212	6.2%	425	12.4%	274	8.0%	186	5.4%	195	5.7%	356	10.4%	3,421
2016	1,141	34.2%	568	17.0%	212	6.4%	470	14.1%	266	7.9%	176	5.3%	200	6.0%	308	9.2%	3,342
2017	1,244	34.8%	585	16.3%	234	6.5%	471	13.2%	293	8.2%	244	6.8%	199	5.6%	309	8.6%	3,578
2018	1,289	35.0%	580	15.7%	240	6.5%	480	13.0%	260	7.1%	245	6.6%	304	8.3%	289	7.8%	3,687
2019	1,425	37.7%	579	15.3%	239	6.3%	480	12.7%	259	6.9%	250	6.6%	278	7.4%	272	7.2%	3,783
2020	1,478	38.4%	596	15.5%	269	7.0%	477	12.4%	272	7.0%	246	6.4%	191	5.0%	323	8.4%	3,851
2021	1,539	36.9%	673	16.1%	299	7.2%	497	11.9%	317	7.6%	262	6.3%	202	4.8%	380	9.1%	4,169
2022	1,677	38.3%	668	15.3%	378	8.6%	495	11.3%	324	7.4%	248	5.7%	188	4.3%	398	9.1%	4,375
2023	1,948	41.4%	672	14.3%	434	9.2%	525	11.2%	312	6.6%	248	5.3%	172	3.7%	391	8.3%	4,702
2024	1,964	41.1%	746	15.6%	349	7.3%	531	11.1%	334	7.0%	317	6.6%	172	3.6%	369	7.7%	4,782
2025	2,133	42.3%	775	15.4%	356	7.1%	574	11.4%	338	6.7%	328	6.5%	172	3.4%	367	7.3%	5,042
2026	2,220	43.0%	789	15.3%	384	7.4%	580	11.2%	339	6.6%	318	6.2%	172	3.3%	360	7.0%	5,161
2027	2,914	49.0%	805	13.5%	389	6.5%	651	10.9%	340	5.7%	321	5.4%	172	2.9%	355	6.0%	5,946
2028	3,133	51.5%	778	12.8%	397	6.5%	640	10.5%	302	5.0%	311	5.1%	165	2.7%	356	5.9%	6,082
2029	3,175	50.7%	830	13.3%	401	6.4%	657	10.5%	341	5.5%	332	5.3%	172	2.8%	352	5.6%	6,259
2030	3,271	51.3%	840	13.2%	405	6.4%	659	10.3%	342	5.4%	339	5.3%	172	2.7%	348	5.5%	6,378
2031	3,276	51.1%	851	13.3%	411	6.4%	662	10.3%	343	5.3%	349	5.4%	172	2.7%	348	5.4%	6,411
2032	3,353	51.5%	862	13.2%	417	6.4%	664	10.2%	343	5.3%	353	5.4%	173	2.6%	349	5.4%	6,514
2033	3,373	51.4%	875	13.3%	423	6.4%	667	10.2%	344	5.2%	357	5.4%	173	2.6%	350	5.3%	6,560
2034	3,379	51.3%	887	13.4%	429	6.5%	670	10.2%	345	5.2%	359	5.4%	173	2.6%	352	5.3%	6,593

WINTER Peak Demand (MW)

	ND	%	SD	%	MN	%	IA	%	NE	%	MT	%	CO	%	WY	%	BEPC TOTAL
00/01	342	27.4%	328	26.2%	57	4.6%	125	10.0%	43	3.4%	34	2.7%	83	6.7%	239	19.1%	1,250
01/02	313	26.2%	300	25.2%	47	3.9%	108	9.1%	37	3.1%	35	2.9%	82	6.9%	270	22.6%	1,193
02/03	377	27.7%	342	25.1%	54	4.0%	128	9.4%	36	2.6%	55	4.0%	103	7.6%	268	19.6%	1,362
03/04	417	27.5%	394	25.9%	60	3.9%	134	8.8%	36	2.3%	62	4.1%	123	8.1%	293	19.3%	1,518
04/05	438	27.4%	417	26.1%	63	3.9%	139	8.7%	44	2.7%	64	4.0%	121	7.6%	314	19.7%	1,599
05/06	463	26.8%	415	24.0%	66	3.8%	187	10.8%	48	2.8%	72	4.2%	121	7.0%	353	20.5%	1,725
06/07	495	25.4%	484	24.9%	111	5.7%	212	10.9%	50	2.6%	71	3.6%	122	6.3%	403	20.7%	1,946
07/08	563	26.3%	524	24.5%	113	5.3%	232	10.8%	50	2.3%	81	3.8%	124	5.8%	454	21.2%	2,140
08/09	623	25.7%	634	26.2%	133	5.5%	276	11.4%	57	2.3%	78	3.2%	138	5.7%	481	19.9%	2,420
09/10	627	23.5%	619	23.2%	169	6.3%	518	19.4%	59	2.2%	74	2.8%	137	5.1%	468	17.5%	2,671
10/11	679	25.2%	622	23.0%	198	7.3%	468	17.4%	55	2.0%	56	2.1%	145	5.4%	477	17.7%	2,698
11/12	835	29.5%	600	21.2%	181	6.4%	443	15.6%	49	1.7%	92	3.2%	180	6.4%	450	15.9%	2,828
12/13	973	32.3%	627	20.8%	194	6.4%	457	15.2%	52	1.7%	101	3.3%	183	6.1%	428	14.2%	3,014
13/14	1,134	31.9%	778	21.9%	253	7.1%	523	14.7%	54	1.5%	183	5.1%	200	5.6%	434	12.2%	3,559
14/15	1,359	37.2%	700	19.2%	233	6.4%	496	13.6%	57	1.6%	191	5.2%	184	5.1%	432	11.8%	3,651
15/16	1,394	39.9%	634	18.2%	229	6.5%	466	13.3%	54	1.5%	161	4.6%	184	5.3%	369	10.6%	3,491
16/17	1,441	38.7%	695	18.7%	249	6.7%	477	12.8%	53	1.4%	242	6.5%	184	5.0%	380	10.2%	3,720
17/18	1,546	39.3%	718	18.3%	281	7.2%	493	12.6%	57	1.4%	245	6.2%	191	4.9%	354	9.0%	3,929
18/19	1,717	42.3%	741	18.2%	289	7.1%	517	12.7%	48	1.2%	236	5.8%	194	4.8%	318	7.8%	4,060
19/20	1,823	44.9%	688	17.0%	235	5.8%	499	12.3%	58	1.4%	256	6.3%	129	3.2%	369	9.1%	4,056
20/21	1,830	43.1%	769	18.1%	284	6.7%	513	12.1%	64	1.5%	256	6.0%	130	3.1%	396	9.3%	4,242
21/22	1,907	43.6%	777	17.8%	331	7.6%	503	11.5%	65	1.5%	245	5.6%	129	2.9%	415	9.5%	4,371
22/23	2,025	43.3%	835	17.8%	393	8.4%	535	11.4%	72	1.5%	267	5.7%	133	2.8%	419	8.9%	4,679
23/24	2,283	46.1%	873	17.6%	351	7.1%	561	11.3%	54	1.1%	304	6.1%	130	2.6%	396	8.0%	4,951
24/25	2,558	48.1%	907	17.1%	358	6.7%	598	11.2%	51	1.0%	328	6.2%	129	2.4%	389	7.3%	5,317
25/26	2,631	48.4%	921	16.9%	383	7.0%	616	11.3%	51	0.9%	328	6.0%	129	2.4%	380	7.0%	5,439
26/27	3,303	53.3%	938	15.1%	387	6.2%	688	11.1%	51	0.8%	330	5.3%	129	2.1%	374	6.0%	6,199
27/28	3,402	54.1%	918	14.6%	394	6.3%	673	10.7%	58	0.9%	322	5.1%	129	2.1%	398	6.3%	6,293
28/29	3,660	55.6%	940	14.3%	397	6.0%	688	10.5%	56	0.8%	330	5.0%	128	1.9%	384	5.8%	6,582
29/30	3,778	56.2%	951	14.1%	401	6.0%	691	10.3%	56	0.8%	337	5.0%	128	1.9%	379	5.6%	6,720
30/31	3,798	56.1%	962	14.2%	405	6.0%	693	10.2%	56	0.8%	346	5.1%	128	1.9%	378	5.6%	6,767
31/32	3,835	55.9%	1,000	14.6%	410	6.0%	702	10.2%	52	0.8%	369	5.4%	129	1.9%	366	5.3%	6,863
32/33	3,915	56.4%	987	14.2%	415	6.0%	699	10.1%	56	0.8%	355	5.1%	128	1.9%	380	5.5%	6,936
33/34	3,929	56.3%	1,000	14.3%	419	6.0%	702	10.1%	56	0.8%	357	5.1%	128	1.8%	383	5.5%	6,975

EXHIBIT 3 - EASTERN SYSTEM SUMMER/WINTER LOADS & RESOURCES

	SPP SUMMER SEASON				
	Members' Load Projections*	Contracted Sales to Others	Firm Purchases	Losses & Reserves	Total Responsibility
2024	3,472	149	-277	650	3,994
2025	3,709	149	-377	676	4,157
2026	3,802	149	-377	694	4,268
2027	4,541	149	-607	794	4,877
2028	4,602	149	-607	806	4,950
2029	4,828	149	-607	850	5,220
2030	4,938	149	-607	872	5,352
2031	4,964	149	-607	877	5,383
2032	5,054	149	-607	895	5,491
2033	5,089	149	-607	902	5,532
2034	5,110	149	-607	906	5,558

	SPP WINTER SEASON				
	Members' Load Projections*	Contracted Sales to Others	Firm Purchases	Losses & Reserves	Total Responsibility
2024/25	3,889	149	-633	666	4,072
2025/26	4,136	149	-643	713	4,355
2026/27	4,863	149	-873	810	4,949
2027/28	4,911	149	-873	820	5,007
2028/29	5,205	149	-873	877	5,358
2029/30	5,337	149	-873	903	5,516
2030/31	5,378	149	-873	911	5,565
2031/32	5,482	149	-873	932	5,690
2032/33	5,527	149	-873	940	5,744
2033/34	5,556	149	-873	946	5,778

	MISO Z1 SUMMER SEASON				
	Members' Load Projections*	Contracted Sales to Others	Firm Purchases	Losses & Reserves	Total Responsibility
2024	267	0	0	32	299
2025	272	0	0	32	304
2026	280	0	0	33	313
2027	284	0	0	34	318
2028	289	0	0	35	323
2029	294	0	0	38	332
2030	298	0	0	39	337
2031	302	0	0	41	344
2032	307	0	0	43	350
2033	312	0	0	44	356
2034	317	0	0	44	362

	MISO Z1 WINTER SEASON				
	Members' Load Projections*	Contracted Sales to Others	Firm Purchases	Losses & Reserves	Total Responsibility
2024/25	298	0	0	96	395
2025/26	306	0	0	99	405
2026/27	311	0	0	100	411
2027/28	315	0	0	94	409
2028/29	319	0	0	96	415
2029/30	322	0	0	96	418
2030/31	326	0	0	97	423
2031/32	330	0	0	98	428
2032/33	334	0	0	99	433
2033/34	338	0	0	100	439

*** Load Projections include diversity adjustments to account for load levels at time of each assessment area's coincident peak**

2024 Resources

Summer Season

	SPP																MISO Z1		
	LOS	LRS East	AVS[2]	Neal4	Wisdom 1&2[3]	SMS	GGS	CGS	DCS	PGS	LCS	New Gas Gen	Member Purchases[1]	Wind	Waste Heat	Solar	SPP Purchases	NTEC CCGT	Cottage Grove	MISO Z1 Purchases
2024	660.0	92.0	900.0	105.1	105.7	97.8	85.0	84.6	297.2	230.6	250.0		168.5	301.6	29.6	81.8	682.4	-	-	323.8
2025	660.0	92.0	900.0	105.1	105.7	97.8	170.0	84.6	297.2	550.6	250.0		157.8	300.0	29.6	81.8	725.4	-	-	409.1
2026	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0		147.5	305.5	29.6	81.8	499.2	-	-	409.1
2027	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0		131.4	301.4	29.6	81.8	499.0	-	-	309.1
2028	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0		127.1	299.2	29.6	81.8	420.8	153.1	228.6	79.1
2029	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0	TBD	124.9	286.9	29.6	81.8	400.4	153.1	228.6	79.1
2030	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0		103.4	284.7	29.6	81.8	405.4	153.1	228.6	79.1
2031	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0		92.1	277.1	29.6	81.8	382.0	153.1	228.6	79.1
2032	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0		91.9	275.1	10.0	81.8	380.9	153.1	228.6	79.1
2033	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0		79.4	273.0	10.0	81.8	353.9	153.1	228.6	4.1
2034	660.0	92.0	900.0	105.1	69.5	97.8	170.0	84.6	297.2	760.8	250.0		79.3	271.0	10.0	81.8	351.4	153.1	228.6	4.1

Winter Season

	SPP																MISO Z1		
	LOS	LRS East	AVS[2]	Neal4	Wisdom 1&2[3]	SMS	GGS	CGS	DCS	PGS	LCS	New Gas Gen	Member Purchases[1]	Wind	Waste Heat	Solar	SPP Purchases	NTEC CCGT	Cottage Grove	MISO Z1 Purchases
2024/25	660.0	92.0	900.0	105.1	111.9	120.0	93.0	95.0	297.0	239.3	270.0		171.1	716.7	29.6	81.8	824.4	-	-	394.6
2025/26	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0		150.5	522.4	29.6	81.8	736.0	-	-	409.3
2026/27	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0		140.1	518.7	29.6	81.8	509.7	-	-	409.3
2027/28	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0		134.0	510.5	29.6	81.8	428.0	-	237.4	309.3
2028/29	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0		129.8	490.2	29.6	81.8	406.2	170.1	237.4	79.3
2029/30	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0	TBD	127.5	486.8	29.6	81.8	412.2	170.1	237.4	79.3
2030/31	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0		92.3	474.3	29.6	81.8	412.1	170.1	237.4	79.3
2031/32	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0		92.1	471.0	10.0	81.8	376.8	170.1	237.4	79.3
2032/33	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0		91.9	467.7	10.0	81.8	349.2	170.1	237.4	79.3
2033/34	660.0	92.0	900.0	105.1	75.0	120.0	188.0	95.0	297.0	805.5	270.0		79.4	464.5	10.0	81.8	345.8	170.1	237.4	4.3

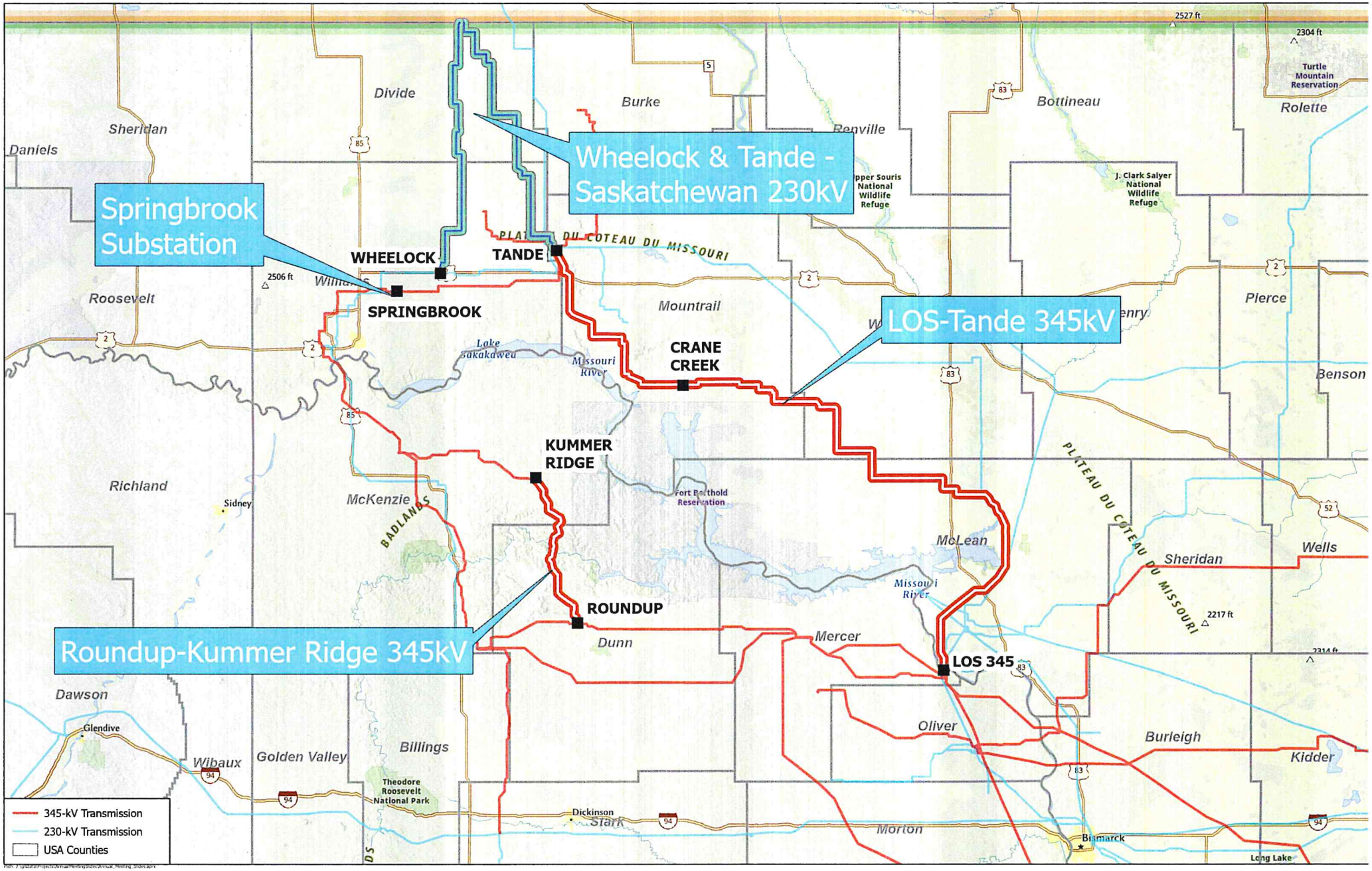
Footnotes:

1) Member Purchases category includes CBPC, NIMECA, and other purchases through special member purchase rates.

2) BEPC owns 24.166% of AVS unit 2 and leases the remaining portion from other owners. The original terms of the lease have been extended by 10 years through 2030.

3) For conservative planning purposes, the financial depreciable life of our generating units is used as their assumed remaining useful life, even though no formal retirement decisions have been made. Actual retirement decisions have to be made by BEPC's Board of Directors.

EXHIBIT 4 - TRANSMISSION PLANNING CORRIDORS


Wheelock & Tande - Saskatchewan 230kV
Springbrook Substation
LOS-Tande 345kV
Roundup-Kummer Ridge 345kV
WHEELOCK
TANDE
SPRINGBROOK
CRANE CREEK
KUMMER RIDGE
ROUNDUP
LOS 345
Divide
Burke
Renville
Bottineau
Rolette
Sheridan
Daniels
Roosevelt
Mountrail
Pierce
Benson
Richland
McKenzie
Sidney
McLean
Sheridan
Wells
Dunn
Mercer
Oliver
Burleigh
Kidder
Dawson
Glendive
Wibaux
Golden Valley
Billings
Dickinson
Stark
Morton
Bismarck
Long Lake
Lake Sakakawea
Missouri River
Fort Berthold Reservation
Turtle Mountain Reservation
J. Clark Salyer National Wildlife Refuge
Theodore Roosevelt National Park
BADLANDS
PLATEAU DU COTEAU DU MISSOURI
2527 ft
2304 ft
2506 ft
2217 ft
345-kV Transmission
230-kV Transmission
USA Counties