BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

June 29, 2018

Mr. Brian Kroshus, Commissioner
North Dakota Public Service Commission
Capitol Building
600 E. Boulevard Ave. - Dept. 408
Bismarck, ND 58505

Dear Commissioner Kroshus:

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,

Paul Sukut
Paul Sukut (Jun 29, 2020 15:45 CDT)

Paul M. Sukut
CEO & General Manager

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Enclosure

1 PU-20-300 Filed 07/01/2020 Pages: 79
2020 Ten Year Plan
Basin Electric Power Cooperative
Paul Sukut, CEO & General Manager

BASIN ELECTRIC POWER COOPERATIVE

A Touchstone Energy® Cooperative 

NORTH DAKOTA TEN YEAR PLAN

2020

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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 five subsidiaries: Dakota Gasification Company, Dakota Coal Company, Montana Limestone Company, Wyoming Line Producers, and Souris Valley Pipeline LTD. 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 sixteen 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 ND1 near Minot; the Minot Wind Project near Minot; the Pioneer Generation Station near Williston; and the Lonesome Creek Generation 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 Chamberlain Wind Project at Chamberlain, 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.

Basin Electric purchases all of the output from Waste Heat Recovery Units located near St. Anthony, North Dakota; Zeeland, North Dakota; Killdeer, North Dakota and three other Heat Recovery Units located in South Dakota; one in Montana; and one in Minnesota. Basin Electric also purchases all the output from the North Dakota 1Wind Energy Center near Edgeley and Kulm, North Dakota; the Wilton Wind Energy Center near Wilton, North Dakota; the Baldwin Wind Project near Baldwin, North Dakota; the South Dakota Wind Energy Center near Highmore, South Dakota; the Day County Wind Project near Groton, South Dakota: the Campbell County Wind Project near Pollock, South Dakota; and the Pipestone, Minnesota School District Wind Turbine. Basin Electric purchases a portion of Unit #4 of the George Neal Station near Salix, Iowa; the City of Madison, South Dakota Diesel Generators; Walter Scott Energy Center Units 3&4 near Council Bluffs, IA; Duane Arnold Energy Center near Palo, Iowa; Wisdom Station Units 1&2 near Spencer, Iowa; Spencer Combustion Turbine, Spencer, Iowa; Estherville, Iowa Diesel Generation; Webster City, Iowa Combustion Turbine; and various wind facilities near Ayrshire, Iowa; Duncan/Klemme County, Iowa; Lakota, Iowa; and Superior, Iowa.

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 does not have any energy conversion facilities under construction.

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

Basin Electric is moving forward with constructing a sixth generating unit at the Lonesome Creek Station near Watford City with construction expected to commence late 2020. This new generator will be identical to the existing five generators at the site. Basin Electric is still evaluating additional development of new generating resources (gas, wind, solar, etc.) to meet Basin Electric's forecasted load growth as it materializes and continue to meet the needs of our membership.

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

Basin Electric is evaluating the development of new generating resources (primarily gas, wind, and solar) in the Dakotas to meet Basin Electric's forecasted load growth.

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-Tioga	05/01/82
Tioga-Canadian Border (Estevan)	05/01/82
Belfield-Rhame	04/07/10
Williston-Tioga	01/10/11
Judson-Williston	12/22/15
Tande-Neset	10/31/17

345 kV Lines

Leland Olds-Groton-Watertown	12/15/75
Leland Olds-Ft. Thompson (SD) 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-Judson	12/22/15
Judson-Kummer Ridge	09/27/16
Judson-Tande	10/31/17

500 kV Lines

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

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

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 Generation 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 the Antelope Valley Station is a forty-two 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.

DGC constructed a 3.5 mile, 10' diameter natural gas pipeline, in late 2013, with the sole purpose to provide AVS with access to natural gas for use only during startup activities.

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. These studies have resulted in the need to construct a 230 kV transmission line from our Neset 230 kV station down to a new 230/115 kV substation near Ross, ND. This project is likely to be in service by the end of 2022 or 2023.

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)

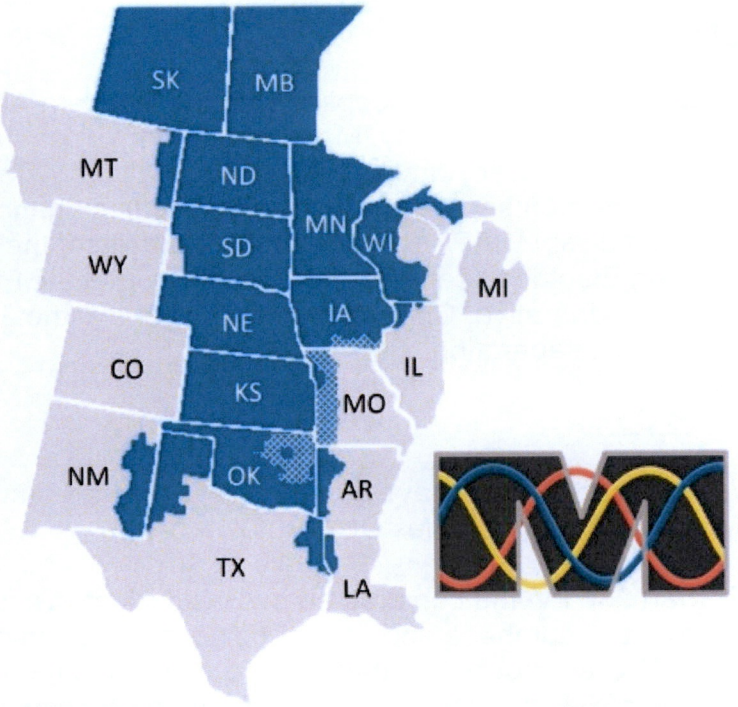
Results of the development of new generating resources (refer to section D) will identify transmission improvements necessary required by the new resources. Transmission studies are underway to analyze the required transmission improvements to accommodate network load growth. Results of these studies may indicate the need for additional load serving transmission facilities.

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 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, to conduct regional assessments of the grid's ability to meet the e 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 Missouri River Basin. Mid-West's Water & Power Marketing Committee meets throughout the year to discuss and review planned additions of Mid-West member utilities.

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.

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 approximately 65,000 miles of high-voltage transmission and 200,000 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. 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.

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, SD, 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. 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.

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 2020. 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+ 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 is 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, MO.; 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 Reserve Group (RMRG) assessment areas. 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, MT,

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 4 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, ND with a net capacity of 221 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 445 MW. Basin Electric installed emission control equipment at the Leland Olds Station which required an increase to the station service. This equipment was put in service after the 2012 fall outage on Unit 2 reducing the net capacity from 448 MW to 445 MW due to additional station service required. The Unit 1 emissions control equipment was placed into service after the spring 2013 maintenance outage.

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

Designed to be environmentally sound, over $397 million have been invested in capital pollution control asset investments for AVS to date. Dry Scrubbers use lime to capture and remove up to 90 percent of sulfur dioxide emissions from stack gases. Fabric filter bag houses capture and remove up to 99 percent of particulate matter. Each bag house contains more than 8,000, 35-foot tall bags. AVS is a "zero-discharge" facility; even water is used efficiently only leaving the plant site through evaporation.

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. The amount of power Basin Electric receives from the eastern unit is 92 MW (net).

Spirit Mound Station: Basin Electric placed in service two 60 MW (net) nameplate fuel oil-fired combustion turbines on June 30, 1978. The combined winter rating of the two units is 120 MW (net) and the summer rating is 100 MW (net). 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, SD.

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, SD. 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 winter rating of 96 MW and Unit 2 has a winter rating of 94 MW.

Culbertson Generation Station: The Culbertson Station is located near Culbertson, MT. Basin Electric commissioned Culbertson Unit 1in 2010. The LMS 100 natural gas unit provides peaking power. The unit has a winter rating of 98 MW.

Deer Creek Station: The Deer Creek Station is located near Brookings, SD. 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 winter rating of 298 MW.

Pioneer Generation Station: The Pioneer Station northwest of Williston, ND 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 have 45 MW of generation capacity and the twelve RICE units have a net generating capacity 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.

Lonesome Creek Generation Station: The Lonesome Creek Station is located near Watford City, ND. Commercial operation for Lonesome Creek Unit 1 began in December 2013, Units 2 and 3 in January 2015, and Units 4 and 5 in March 2017. Each unit consists of a LM 6000 natural gas unit and provides peaking power. Each unit has a winter rating of 45 MW for a total station generation capacity is 225MW. Unit 1 has a synchronous clutch located between the combustion turbine and generator allowing the generator rotor to spin independent of the turbine providing voltage stability to the electric grid. In 2020

Basin Electric's Board of Directors approved constructing a sixth unit, identical to the existing five units at the site, with an expected commercial operation date in late 2021. Construction on the new unit is expected to commence before the end of 2020.

Chamberlain Wind Project: Basin Electric, in partnership with East River Power Cooperative, has constructed a wind energy project near Chamberlain, South Dakota. The 2.6 megawatt capacity project was placed into commercial service in January 2002. The energy is delivered to members as part of Basin Electric's overall power supply.

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 2.6 megawatt capacity wind project was placed into commercial service in February 2002. Three additional turbines were added in December 2009 for a total output of 7.1 megawatts. 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 115.5 MW capacity wind project 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 162 MW capacity wind project was placed into commercial service in 2011. Basin Electric owns 107 turbines or 160.5 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 period.

George Neal IV: Basin Electric and Northwest Iowa Power Cooperative (NIPCO), one of Basin Electric's member cooperative, 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 (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 73 MW of uncommitted capacity and associated energy from Unit No. 4 of the George Neal Generating Station (Neal IIV). 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.

Walter Scott 3 and 4: 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 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 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.

Duane Arnold Energy Center: Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated with a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 62 MW of uncommitted capacity and associated energy from the Duane Arnold Energy Center. In return, Com Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Com 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 2018 NextEra Energy Resources, the majority owner and operator of the Duane Arnold Energy Center, announced they will be retiring the facility by the end of 2020.

Western Native American Purchase: Basin Electric receives a Native American Allocation of 39.7 MW in the winter and 40.8 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, SD. 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, NE. Basin Electric has acquired all 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 and vice versa.

Sidney DC Tie: Western Area Power Administration constructed a 200 MW asynchronous tie at Sidney, NE. 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, ND
    - two 49.5 MW projects near Wilton, ND

- 100 MW near Baldwin, ND
- 40 MW near Highmore SD
- 94 MW near Pollock, SD
- 99 MW near Groton, SD
- 104 MW near Hebron, ND
- 150 MW near Tioga, ND
- Two 150 MW projects near New England, ND
- 200 MW near Columbus, ND (expected COD 12/2020)
- 200 MW near Avon, SD (COD Spring 2020)
- 142 MW near Tioga, ND (term starting 1/2023)

- Solar Purchases:
  - 128 MW near Rapid City, SD (expected COD 1/2023)
  - Two 75 MW near Baker, MT (expected COD 1/2024)

- Peaking Purchases:
  - 10 MW City of Madison, SD diesel generators
  - Eight 5.5 MW waste heat recover units from Ormat Technologies Inc. (3 sites in SD near Wetonka, Clark, and Estelline; 3 in ND; 1 in MT; 1 in MN)
  - 92 MW in purchases from CBPC
    - 24.8 MW from Webster City, IA
    - 12.1 MW from Estherville, IA
    - 10 MW from Spencer, IA
    - 45.1 MW from their share of the Superior, Lakota, Hancock, and Crosswinds wind projects in IA
  - ~70 MW from North Iowa Municipal Electric Cooperative Association's (NIMECA's) surplus capacity resources in IA

- Other Long Term PPAs:
  - Capacity and Energy
    - 100 MW during the summer from Minnkota Power Cooperative (3/2019-5/2022)
  - Capacity Only
    - 75-125 MW from Minnesota Power (6/2022-5/2025)
    - 100 MW from Minnesota Power (6/2025-5/2028)
    - 75 MW from Great River Energy (6/2020-5/2023)
    - 50 MW from Manitoba Hydro (ending 5/2021)
    - 50-80 MW from Manitoba Hydro (6/2023-5/2028)
    - 75-175 MW from Dairyland Power Cooperative (6/2019-5/2023)
    - 75 MW from Dairyland Power Cooperative (6/2023-5/2033)
    - 150 MW from Missouri River Energy Services (ending 9/2023)
    - 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)

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, MT. 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 Antelope Valley Station.

Wyoming Distributed Generation: The Wyoming Distributed Generation consists of 9 peaking units located at 3 sites; Arvada, Hartzog and Barber Creek. These units are natural gas fired units with a total net output of 45 MW summer and 54 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 became fully operational in November of 2011. Basin Electric owns 92.9% of the station or 376 MW (net).

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

- 50 MW from MacQuarie Energy (formerly "Cargill"; ending 12/2021)
- 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	ND Lignite Coal	Rail
Spirit Mound Station	Oil	Pipeline
Laramie River Station	Wyoming (PRB) Coal	Rail
Antelope Valley Station	ND Lignite Coal	Mine Mouth/Rail
Minot Wind Project	Wind	N/A
Wyoming Distributed Gen	Natural Gas	Pipeline
Wisdom Unit 2	Natural Gas/Fuel Oil	Pipeline
Chamberlain Wind Project	Wind	N/A
Groton Generation Station	Natural Gas	Pipeline
PrairieWinds 1 Wind Project	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	Wyoming (PRB) Coal	Mine Mouth
Pioneer Gen Station	Natural Gas	Pipeline
Lonesome Creek Gen 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	25-MAR-19
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	Joseph Leingang				
Title	Director of Fuels				
Address	1717 E. Interstate Avenue				
City/State/Zip	Bismarck		ND 58503		
Email	jleingang@bepc.com		Phone	(701) 557-5648	Fax (701) 557-5144

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

Total Sources must equal Total Disposition (3 = 11)

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

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

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

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

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

Sales for Resale are energy supplied to electric utilities, cooperatives, municipalities, federal and state 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

Combustion Byproduct	Disposal			Beneficial Use		Storage		Total
	On-site Landfill	Disposal On-site Ponds	Disposal Off-site	Sold	Used On-site	Used Off-site	Storage Stored On-site	Stored Off-site	
Fly ash from standard boiler/PCD units			96.9	25.3					122.2
Fly ash from units with dry FGD									
Fly ash from FBC units									
Bottom ash from standard boiler units			144.7	0.0					144.7
Bottom (bed) ash from FBC units									
FGD Gypsum			146.9	14.6					161.5
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	2,001	1,299	7,163	0	91	10,554
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	0	29	34,031	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	53	12	0	0	0	65

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

eport 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
es	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)
I				1	OP	8254												90.4	2.04	
			1		OP	8254	.1465	.149												
			1		OP	8254	.1465	.149												
I				2	OP	6508												89.1	2.28	
			2		OP	6508	.3	.306												
	1			1B	OP	8254			.008	79.8	99.8	12-1974								
	2			2B	OP	6508			.0083	80.6	99.5	12-1976								
			1		OP	8254	.1465	.149												
			2		OP	6508	.3	.306												
		1		1C	OP	8254							78.2	97.7	08-2013	31.5	38134			

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
...es	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)
		2		2C	OP	6508						79.9	98.7	01-2013	52.1	68486			

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	$1,055	$191	$57	$1,441	$2,744
2	$1,776	$358	$101	$1,984	$4,219

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

oling stem 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
port Month 1																		
	ON	OP	744	0		71438	71438	0	4	40	44	57	67	1		3188.98	3188.98	0
port Month 2																		
	ON	OP	672	0		717300	71730	0	4	38	41	43	51	1		2892.167	2892.167	0
port Month 3																		
	ON	OP	743	0		67726	67726	0	4	41	44	44	51	1		3016.503	3016.503	0
port Month 4																		
	ON	OP	720	0		50547	50547	0	4	41	48	50	65	1		2183.637	2183.637	0
port Month 5																		
	ON	OP	744	0		71904	71904	0	4	53	74	56	74	1		3209.809	3209.809	0
port Month 6																		
	ON	OP	720	0		71872	71872	0	4	62	78	71	83	1		3104.86	3104.86	0

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

mplete 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 gawatts.

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oling stem 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
port Month 7																		
	ON	OP	744	0		71648	71648	0	4	55	59	77	83	1		3198.367	3198.367	0
port Month 8																		
	ON	OP	744	0		71634	71634	0	4	57	61	77	91	1		3195.61	3195.61	0
port Month 9																		
	ON	OP	720	0		71468	71468	0	4	59	62	74	88	1		3087.436	3087.436	0
port Month 10																		
	ON	OP	742	0		66638	66638	0	4	55	61	71	91	1		2966.384	2966.384	0
port Month 11																		
	ON	OP	720	0		71792	71792	0	4	47	52	66	76	1		3105.707	3105.707	0
port Month 12																		
	ON	OP	744	0		71710	71710	0	4	41	45	58	71	1		3201.141	3201.141	0

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f 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)**			
ooling stem 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	Consumptio
port Month 1																		
	ON	OP	744	0		149260	149260	0	4	40	44	65	73	1		6662961	6662961	0
port Month 2																		
	ON	OP	672	0		149416	149416	0	4	38	41	61	71	1		6024.453	6024.453	0
port Month 3																		
	ON	OP	743	0		149410	149410	0	4	41	44	65	75	1		6660.701	6660.701	0
port Month 4																		
	ON	OP	720	0		130291	130291	0	4	41	48	59	79	1		5628.567	5628.567	0
port Month 5																		
	ON	OP	252	0		74435	74435	0	4	53	74	56	66	1		1123.134	1123.134	0
port Month 6																		
	ON	OP	230	0		84971	84971	0	4	62	78	71	71	1		1169.945	1169.945	0

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

oling stem 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
port Month 7																		
	ON	OP	744	0		149296	149296	0	4	55	59	80	86	1		664.574	664.574	0
port Month 8																		
	ON	OP	744	0		149282	149282	0	4	57	61	80	90	1		6663.956	6663.956	0
port Month 9																		
	ON	OP	720	0		149347	149347	0	4	59	62	83	93	1		6451.785	6451.785	0
port Month 10																		
	ON	OP	744	0		149343	149343	0	4	55	61	78	91	1		6666.665	6666.665	0
port Month 11																		
	ON	OP	720	0		149583	149583	0	4	47	52	54	70	1		6470.973	6470.973	0
port Month 12																		
	ON	OP	744	0		148827	148827	0	4	41	45	60	72	1		6643.648	6643.648	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
		8A					811 Revenue of bottom ash was reported on Schedule 8B Part 12, but the quantity of bottom ash sold has not been reported on Schedule 8A. Please enter the required data for Schedule 8A or provide an explanation		This is actually for slag sold in 2017 that was not recorded as revenue until 2018.
		8B					837 Sales of FGD By-products (Lines 6 and 7) were reported on Schedule 8, Part A. Please enter the revenue (Part 14) in units of thousand dollars from those sales on Schedule 8B. Example: enter revenue of 5 million dollars as 5,000, not 5,000,000.		Sales of FGD By-products were $1.00 which is less than what can be entered.
		8C		1B/EK			882 Mercury Removal Efficiency cannot be null if hours in service were reported. Please review reported data.		This equipment is intended for particulate control. While it may remove mercury, removal efficiency is unknown.
		8C		1C/SP			882 Mercury Removal Efficiency cannot be null if hours in service were reported. Please review reported data.		This equipment is intended for SO2 control. While it may remove mercury, removal efficiency is unknown.
		8C		1C/SP			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		This equipment is intended for SO2 control while it may remove acid gases, that is not its intended function so removal efficiency 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 removal efficiency is 98.7% which is within the expected range of 50%-99%.
		8C		2B/EK			882 Mercury Removal Efficiency cannot be null if hours in service were reported. Please review reported data.		This equipment is intended for particulate control. While it may remove mercury, removal efficiency is unknown.
		8C		2C/SP			882 Mercury Removal Efficiency cannot be null if hours in service were reported. Please review reported data.		This equipment is intended for SO2 control. While it may remove mercury, removal efficiency is unknown.
		8C		2C/SP			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		This equipment is intended for SO2 control while it may remove acid gases, that is not its intended function so removal efficiency is unknown.

Supplemental EIA923 Power Plant Operations Report

Year: **2019** Plant: **2817** **Leland Olds**

OMB No. 1905-0129
Approval Expires 03/31/2020

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	26-MAR-20
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	Joseph Leingang				
Title	Director of Fuels				
Address	1717 E. Interstate Avenue				
City/State/Zip	Bismarck	ND	58503		
Email	jleingang@bepc.com	Phone	(701) 557-5648	Fax	(701) 557-5144

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

Total Sources must equal Total Disposition (3 = 11)

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

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

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

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

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

Sales for Resale are energy supplied to electric utilities, cooperatives, municipalities, federal and state 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			95.4	34.4					129.8
Fly ash from units with dry FGD									
Fly ash from FBC units									
Bottom ash from standard boiler units			141.6	19.2					160.8
Bottom (bed) ash from FBC units									
FGD Gypsum			97.0	29.4					126.4
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	2,199	1,409	9,902	0	101	13,611
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	0	56	10,840	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	484	49		1		534

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

eport 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
es	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)
I				1	OP	7827											86	2.95	
			1		OP	7827	.1387 .134												
			1		OP	7827	.1387 .134												
I				2	OP	7408											87.4	2.65	
			2		OP	7408	.2842 .28												
	1			1B	OP	7827		.008	99	99.8	12-1974						86	2.95	
	2			2B	OP	7408		.0083	99	99.5	12-1976						87.4	2.65	
			1		OP	7827	.1387 .134												
			2		OP	7408	.2842 .28												
		1		1C	OP	7827						97	97.7	08-2013	29.8	38723	86	2.95	

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
ıes 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)
	2		2C	OP	7408							98	98.7	01-2013	55.9	78365	87.4	2.65	

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	$1,065	$194	$222	$1,805	$3,286
2	$2,155	$390	$439	$3,632	$6,616

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

oling stem 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
port Month 1																		
	ON	OP	744	0		70441	70441	0	4	39	41	57	66	1		3144.492	3144.492	0
port Month 2																		
	ON	OP	672	0		71654	71654	0	4	38	40	62	66	1		2889.087	2889.087	0
port Month 3																		
	ON	OP	743	0		71753	71753	0	4	39	44	57	67	1		3198.737	3198.737	0
port Month 4																		
	ON	OP	720	0		71791	71791	0	4	40	45	59	70	1		3101.36	3101.36	0
port Month 5																		
	ON	OP	744	0		71674	71674	0	4	44	52	60	76	1		3199.54	3199.54	0
port Month 6																		
	ON	OP	720	0		71671	71671	0	4	51	57	67	78	1		3096.173	3096.173	0

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

oling stem 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
port Month 7																		
	ON	OP	744	0		71647	71647	0	4	54	59	71	82	1		3198.333	3198.333	0
port Month 8																		
	ON	OP	744	0		71662	71662	0	4	57	64	72	88	1		3198.984	3198.984	0
port Month 9																		
	ON	OP	720	0		67965	67965	0	4	61	65	74	88	1		2934.581	2934.581	0
port Month 10																		
	ON	OP	744	0		71818	71818	0	4	55	61	58	84	1		3205.95	3205.95	0
port Month 11																		
	ON	OP	720	0		71665	71665	0	4	48	53	64	78	1		3100.22	3100.22	0
port Month 12																		
	ON	OP	744	0		71675	71675	0	4	41	47	50	73	1		3199.572	3199.572	0

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f 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)**			
oling stem 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	Consumptio
port Month 1																		
	ON	OP	744	0		149313	149313	0	4	39	41	64	71	1		6665.327	6665.327	0
port Month 2																		
	ON	OP	672	0		149308	149308	0	4	38	40	62	68	1		6020.093	6020.093	0
port Month 3																		
	ON	OP	743	0		117539	117539	0	4	39	44	50	73	1		5239.88	5239.88	0
port Month 4																		
	ON	OP	720	0		116241	116241	0	4	40	45	50	72	1		5021.619	5021.619	0
port Month 5																		
	ON	OP	744	0		149349	149349	0	4	44	52	66	81	1		6666.921	6666.921	0
port Month 6																		
	ON	OP	720	0		149341	149341	0	4	51	57	72	83	1		6451.546	6451.546	0

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f 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)**			
ooling stem ID	Cooling System Type	Cooling System Status	Hours in Service Per monthe	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	Consumptio
port Month 7																		
	ON	OP	744	0		147705	147705	0	4	54	59	74	85	1		6593.556	6593.556	0
port Month 8																		
	ON	OP	744	0		147929	147929	0	4	57	64	77	93	1		6603.558	6603.558	0
port Month 9																		
	ON	OP	720	0		149596	149596	0	4	61	65	71	91	1		6457.861	6457.861	0
port Month 10																		
	ON	OP	744	0		149636	149636	0	4	55	61	67	83	1		6679.741	6679.741	0
port Month 11																		
	ON	OP	720	0		149330	149330	0	4	48	53	70	80	1		6460	6460	0
port Month 12																		
	ON	OP	744	0		149350	149350	0	4	41	47	66	76	1		6666.983	6666.983	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 data entered is correct.
		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.

Supplemental EIA923 Power Plant Operations Report

Year: **2018** Plant: **6469** **Antelope Valley**

OMB No. 1905-0129
Approval Expires 03/31/2020

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	
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	Joseph Leingang				
Title	Director of Fuels				
Address	1717 E. Interstate Avenue				
City/State/Zip	Bismarck		ND 58503		
Email	jleingang@bepc.com		Phone	(701) 557-5648	Fax (701) 557-5144

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			727.7	0.0		21.8			749.5
Fly ash from FBC units									
Bottom ash from standard boiler units			181.9						181.9
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	2,352	1,017	21,623	0	1,567	26,559
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	8	24	8	

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

eport 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
ıes	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)
			B1		OP	8207	.1033	.103												
				1	OP	8207												88.7	2.37	
			B1		OP	8207	.1033	.103												
			B2		OP	7753	.1021	.104												
				2	OP	7753												86.4	2.84	
			B2		OP	7753	.1021	.104												
	BH1			1	OP	8207			.0035	70.9	99.9	06-1983								
	BH2			2	OP	7753			.0032	70.9	99.9	08-1986								
		FGD1		1	OP	8207								63.9	09-1983	49.9	13542			
		FGD2		2	OP	7753								85.8	08-1986	48.6	13607			

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
es	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	$5,335	$2,721	$657	$1,745	$10,458
FGD2	$5,208	$2,725	$641	$2,591	$11,165

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

oling stem 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
port Month 1																		
1	RF	OP	744	4.606	3076.2	3076.2	0	3076.2	2	32				7	137.331	137.331	0	137.331
port Month 2																		
1	RF	OP	574	3.384	2501.6	2501.6	0	2501.6	2	32				7	100.872	100.872	0	100.872
port Month 3																		
1	RF	OP	743	4.609	3077.9	3077.9	0	3077.9	2	32				7	137.408	137.408	0	137.408
port Month 4																		
1	RF	OP	677	3.999	2759.8	2759.8	0	2759.8	2	41				7	119.23	119.23	0	119.23
port Month 5																		
1	RF	OP	638	4.262	2846.1	2846.1	0	2846.1	2	60				7	127.057	127.057	0	127.057
port Month 6																		
1	RF	OP	697	5.249	3622	3622	0	3622	2	65				7	156.479	156.479	0	156.479

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

oling stem 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
port Month 7																		
1	RF	OP	744	5.863	3915.5	3915.5	0	3915.5	2	71				7	174.801	174.801	0	174.801
port Month 8																		
1	RF	OP	744	5.964	3982.5	3982.5	0	3982.5	2	68				7	177.79	177.79	0	177.79
port Month 9																		
1	RF	OP	718	5.104	3522.3	3522.3	0	3522.3	2	58				7	152.173	152.173	0	152.173
port Month 10																		
1	RF	OP	399	2.539	1695.8	1695.8	0	1695.8	2	46				7	75.705	75.705	0	75.705
port Month 11																		
1	RF	OP	720	4.59	3167.3	3167.3	0	3167.3	2	36				7	136.838	136.838	0	136.838
port Month 12																		
1	RF	OP	744	3.784	2526.7	2526.7	0	2526.7	2	33				7	112.799	112.799	0	112.799

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

mplete 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 gawatts.

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oling stem 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
port Month 1																		
2	RF	OP	698	4.154	2872.9	2872.9	0	2872.9	2	32				7	128.147	128.147	0	128.147
port Month 2																		
2	RF	OP	621	3.653	2797.3	2797.3	0	2797.3	2	32				7	112.703	112.703	0	112.703
port Month 3																		
2	RF	OP	607	3.656	2528.9	2528.9	0	2528.9	2	32				7	112.803	112.803	0	112.803
port Month 4																		
2	RF	OP	720	4.578	3272.2	3272.2	0	3272.2	2	41				7	141.25	141.25	0	141.25
port Month 5																		
2	RF	OP	548	3.927	2716.4	2716.4	0	2716.4	2	60				7	121.168	121.168	0	121.168
port Month 6																		
2	RF	OP	666	4.864	3476.1	3476.1	0	3476.1	2	65				7	150.052	150.052	0	150.052

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

mplete 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 gawatts.

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					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)**			
ooling stem ID	Cooling System Type	Cooling System Status	Hours in Service Per monthe	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	Consumptio
port Month 7																		
2	RF	OP	744	5.673	3924	3924	0	3924	2	71				7	175.032	175.032	0	175.032
port Month 8																		
2	RF	OP	742	5.69	3935.3	3935.3	0	3935.3	2	68				7	175.538	175.538	0	175.538
port Month 9																		
2	RF	OP	611	3.97	2837.6	2837.6	0	2837.6	2	58				7	122.49	122.49	0	122.49
port Month 10																		
2	RF	OP	607	3.975	2749.6	2749.6	0	2749.6	2	46				7	122.647	122.647	0	122.647
port Month 11																		
2	RF	OP	548	3.287	2348.9	2348.9	0	2348.9	2	36				7	101.394	101.394	0	101.394
port Month 12																		
2	RF	OP	541	3.267	2259.4	2259.4	0	2259.4	2	33				7	100.781	100.781	0	100.781

SCHEDULE 9. COMMENTS

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

Schedule	Part	Item	Comments
8	C	OT	Liquid injection into the scrubber.
8	D	F	Cooling water temperature method of measurement is USGS data from lake for all

Generator Retirement Dates

Generator Id	Retirement Month	Retirement Year	Comments

Changes in Ownership (Provide name of purchaser and date sold.)

ERRORS

urchase 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.
		8C		1/BR			882	Mercury Removal Efficiency cannot be null if hours in service were reported. Please review reported data.		This equipment is intended for particulate control. While it may remove mercury, removal efficiency is unknown.
		8C		1/SD			882	Mercury Removal Efficiency cannot be null if hours in service were reported. Please review reported data.		This equipment is intended for SO2 control. While it may remove mercury, removal efficiency is unknown.
		8C		1/SD			890	Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		This equipment is intended for SO2 control. While it may remove acid gases, removal efficiency is unknown.
		8C		2/BR			882	Mercury Removal Efficiency cannot be null if hours in service were reported. Please review reported data.		This equipment is intended for particulate control. While it may remove mercury, removal efficiency is unknown.
		8C		2/SD			882	Mercury Removal Efficiency cannot be null if hours in service were reported. Please review reported data.		This equipment is intended for SO2 control. While it may remove mercury, removal efficiency is unknown.
		8C		2/SD			890	Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		This equipment is intended for SO2 control. While it may remove acid gases, removal efficiency is unknown.
		8D					864	The code for "Other" was selected for the 'Measured or Estimated' Water Temperature. Specify the method in an override comment.		This was done.

U.S. Department of Energy
nergy Information Administration
orm EIA-923

Supplemental EIA923 Power Plant Operations Report

Year: **2019** Plant: **6469** **Antelope Valley**

OMB No. 1905-0129
Approval Expires 03/31/2020

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	26-MAR-20
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	Joseph Leingang				
Title	Director of Fuels				
Address	1717 E. Interstate Avenue				
City/State/Zip	Bismarck	ND	58503		
Email	jleingang@bepc.com	Phone	(701) 557-5648	Fax	(701) 557-5144

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

Total Sources must equal Total Disposition (3 = 11)

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

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

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

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

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

Sales for Resale are energy supplied to electric utilities, cooperatives, municipalities, federal and state 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									0.0
Fly ash from units with dry FGD			666.1	0.0		31.4			697.5
Fly ash from FBC units									0.0
Bottom ash from standard boiler units			166.5						166.5
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	2,288	991	22,273	0	1,616	27,168
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	9	0	0	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						

SCHEDULE 8. PART C. AIR EMISSIONS COMTROL INFORMATION

eport 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
es	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)
			B1		OP	8525	.1059	.107												
				1	OP	8525												89.2	2.27	
			B1		OP	8525	.1059	.107												
			B2		OP	7413	.1055	.107												
				2	OP	7413												87.2	2.68	
			B2		OP	7413	.1055	.107												
	BH1			1	OP	8525			.0035	99	99.9	09-1983						87.2	2.68	
	BH2			2	OP	7413			.0032	99	99.9	08-1986						87.2	2.68	
		FGD1		1	OP	8525							63	63.9	09-1983	50.2	14067	89.2	2.27	
		FGD2		2	OP	7413							85	85.8	08-1986	45.9	13009	87.2	2.68	

Supplemental EIA923 Power Plant Operations Report

Year: **2019** Plant: **6469** **Antelope Valley**

OMB No. 1905-0129
Approval Expires 03/31/2020

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
ues	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	$5,398	$2,806	$667	$1,820	$10,691
FGD2	$4,919	$2,814	$607	$3,242	$11,582

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

mplete 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 gawatts.

Complete a seperate schedule for each reporting month.

Complete a seperate row for each cooling system.

f actual data are not available, provided an estimated value.

f 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)**			
ooling stem ID	Cooling System Type	Cooling System Status	Hours in Service Per monthe	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	Consumptio
port Month 1																		
1	RF	OP	744	2.843	2225	2225	0	2225	2	32				7	99.319	99.319	0	99.319
port Month 2																		
1	RF	OP	672	2.895	2509	2509	0	2509	2	32				7	101.151	101.151	0	101.151
port Month 3																		
1	RF	OP	743	4.098	3207	3207	0	3207	2	32				7	143.169	143.169	0	143.169
port Month 4																		
1	RF	OP	720	4.089	3306	3306	0	3306	2	44				7	142.843	142.843	0	142.843
port Month 5																		
1	RF	OP	687	3.751	2936	2936	0	2936	2	50				7	131.053	131.053	0	131.053
port Month 6																		
1	RF	OP	720	4.301	3478	3478	0	3478	2	63				7	150.25	150.25	0	150.25

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
port Month 7																		
1	RF	OP	712	4.515	3533	3533	0	3533	2	70				7	157.727	157.727	0	157.727
port Month 8																		
1	RF	OP	744	4.662	3648	3648	0	3648	2	68				7	162.866	162.866	0	162.866
port Month 9																		
1	RF	OP	720	4.155	3360	3360	0	3360	2	60				7	145.145	145.145	0	145.145
port Month 10																		
1	RF	OP	615	3.012	2357	2357	0	2357	2	48				7	105.227	105.227	105.227	105.227
port Month 11																		
1	RF	OP	720	3.614	2923	2923	0	2923	2	38				7	126.266	126.266	0	126.266
port Month 12																		
1	RF	OP	684	3.602	2819	2819	0	2819	2	32				7	125.853	125.853	0	125.853

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
port Month 1																		
2	RF	OP	744	3.777	3047	3047	0	3047	2	32				7	136.034	136.034	0	136.034
port Month 2																		
2	RF	OP	620	3.104	2773	2773	0	2773	2	32				7	111.798	111.798	0	111.798
port Month 3																		
2	RF	OP	743	3.975	3207	3207	0	3207	2	32				7	143.169	143.169	0	143.169
port Month 4																		
2	RF	OP	457	2.514	2096	2096	0	2096	2	44				7	90.56	90.56	0	90.56
port Month 5																		
2	RF	OP	0	0	0	0	0	0	2	50				7	0	0	0	0
port Month 6																		
2	RF	OP	490	2.712	2261	2261	0	2261	2	63				7	97.688	97.688	0	97.688

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
port Month 7																		
2	RF	OP	670	4.107	3314	3314	0	3314	2	70				7	147.946	147.946	0	147.946
port Month 8																		
2	RF	OP	744	4.522	3648	3648	0	3648	2	68				7	162.866	162.866	0	162.866
port Month 9																		
2	RF	OP	665	3.69	3076	3076	0	3076	2	60				7	132.911	132.911	0	132.911
port Month 10																		
2	RF	OP	744	3.629	2928	2928	0	2928	2	48				7	130.708	130.708	0	130.708
port Month 11																		
2	RF	OP	720	3.548	2958	2958	0	2958	2	38				7	127.791	127.791	0	127.791
port Month 12																		
2	RF	OP	744	3.846	3103	3103	0	3103	2	32				7	138.544	138.544	0	138.544

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 the equipment does remove acid gases, the amount of control is unknown.
		8C		2/SD			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		While the equipment does remove acid gases, the amount of control 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.

Basin Electric Member Loads by State

Note: Historical 1995-2019 and Forecasted 2020-2030

SUMMER Peak Demand (MW)

	ND	%	SD	%	MN	%	IA	%	NE	%	MT	%	CO	%	WY	%	BEPC TOTAL
1995	223.9	22.3%	235.9	23.5%	38.9	3.9%	71.6	7.1%	186.2	18.5%	21.2	2.1%	77.9	7.8%	148.9	14.8%	1004.5
1996	222.1	22.6%	220.2	22.4%	38.4	3.9%	67.0	6.8%	170.2	17.3%	27.8	2.8%	78.2	7.9%	160.7	16.3%	984.7
1997	244.0	22.6%	239.0	22.2%	41.3	3.8%	77.6	7.2%	195.5	18.1%	26.8	2.5%	82.3	7.6%	171.6	15.9%	1078.1
1998	248.7	21.8%	273.0	24.0%	47.1	4.1%	83.2	7.3%	211.3	18.6%	28.1	2.5%	84.3	7.4%	162.8	14.3%	1138.4
1999	267.9	22.4%	288.5	24.2%	52.5	4.4%	102.2	8.6%	197.4	16.5%	28.3	2.4%	83.9	7.0%	173.8	14.6%	1194.5
2000	292.6	23.0%	301.7	23.7%	53.9	4.2%	98.7	7.8%	214.9	16.9%	28.9	2.3%	82.4	6.5%	199.9	15.7%	1273.0
2001	306.5	22.2%	342.5	24.8%	58.0	4.2%	116.0	8.4%	227.3	16.5%	30.3	2.2%	81.9	5.9%	217.9	15.8%	1380.4
2002	315.3	21.3%	351.9	23.8%	57.7	3.9%	127.1	8.6%	253.5	17.1%	43.9	3.0%	94.6	6.4%	235.5	15.9%	1479.6
2003	353.0	22.9%	345.5	22.4%	57.8	3.8%	121.4	7.9%	239.1	15.5%	55.9	3.6%	114.0	7.4%	253.9	16.5%	1540.6
2004	328.8	21.2%	353.9	22.8%	55.4	3.6%	119.0	7.7%	233.4	15.0%	61.8	4.0%	130.1	8.4%	271.3	17.5%	1553.6
2005	356.6	20.7%	400.1	23.2%	62.0	3.6%	131.1	7.6%	269.7	15.7%	74.2	4.3%	131.6	7.6%	296.4	17.2%	1721.6
2006	400.0	20.5%	440.4	22.6%	71.4	3.7%	187.9	9.7%	272.9	14.0%	82.0	4.2%	134.3	6.9%	358.0	18.4%	1946.9
2007	451.9	21.9%	460.8	22.3%	91.6	4.4%	186.1	9.0%	261.6	12.7%	86.4	4.2%	135.2	6.6%	388.9	18.9%	2062.5
2008	464.6	22.5%	420.7	20.4%	87.5	4.2%	177.0	8.6%	270.1	13.1%	73.8	3.6%	142.2	6.9%	426.4	20.7%	2062.3
2009	448.3	21.4%	437.5	20.9%	101.6	4.9%	201.0	9.6%	231.5	11.1%	64.8	3.1%	145.4	7.0%	400.1	19.1%	2090.1
2010	509.1	20.5%	472.3	19.0%	181.0	7.3%	459.1	18.5%	237.9	9.6%	69.6	2.8%	145.4	5.9%	407.1	16.4%	2481.5
2011	543.4	20.8%	548.4	21.0%	169.2	6.5%	460.4	17.7%	280.3	10.8%	69.3	2.7%	139.6	5.4%	396.3	15.2%	2606.9
2012	693.0	23.1%	595.9	19.9%	206.5	6.9%	476.1	15.9%	333.4	11.1%	104.4	3.5%	207.8	6.9%	377.2	12.6%	2994.2
2013	812.2	26.5%	571.6	18.7%	223.5	7.3%	459.6	15.0%	298.9	9.8%	147.0	4.8%	179.7	5.9%	370.0	12.1%	3062.6
2014	889.0	29.3%	507.5	16.8%	159.9	5.3%	433.1	14.3%	311.2	10.3%	178.2	5.9%	178.5	5.9%	372.0	12.3%	3029.3
2015	1186.6	34.7%	587.0	17.2%	211.7	6.2%	425.1	12.4%	273.6	8.0%	186.1	5.4%	194.6	5.7%	356.1	10.4%	3420.7
2016	1141.3	34.2%	567.8	17.0%	212.4	6.4%	470.3	14.1%	265.5	7.9%	176.4	5.3%	200.4	6.0%	307.6	9.2%	3341.7
2017	1243.5	34.8%	584.6	16.3%	234.3	6.5%	470.9	13.2%	293.3	8.2%	244.0	6.8%	199.1	5.6%	308.6	8.6%	3578.4
2018	1288.7	35.0%	580.4	15.7%	239.5	6.5%	479.8	13.0%	260.4	7.1%	244.5	6.6%	304.3	8.3%	289.2	7.8%	3686.8
2019	1425.4	37.7%	579.1	15.3%	238.7	6.3%	479.6	12.7%	259.2	6.9%	250.4	6.6%	278.3	7.4%	272.4	7.2%	3783.2
2020	1435.8	37.4%	587.3	15.3%	264.0	6.9%	479.4	12.5%	311.0	8.1%	258.7	6.7%	269.2	7.0%	229.4	6.0%	3834.8
2021	1482.1	36.6%	617.3	15.2%	284.6	7.0%	521.9	12.9%	312.7	7.7%	259.8	6.4%	269.4	6.6%	304.4	7.5%	4052.2
2022	1700.7	39.5%	642.9	14.9%	292.6	6.8%	528.5	12.3%	314.2	7.3%	261.8	6.1%	269.7	6.3%	300.1	7.0%	4310.5
2023	1887.2	40.2%	750.7	16.0%	301.0	6.4%	532.4	11.3%	315.6	6.7%	344.7	7.3%	269.9	5.7%	294.5	6.3%	4695.9
2024	2031.0	41.3%	783.8	15.9%	310.2	6.3%	536.2	10.9%	316.9	6.4%	379.1	7.7%	270.1	5.5%	291.4	5.9%	4918.7
2025	2126.4	42.2%	795.7	15.8%	320.7	6.4%	540.1	10.7%	318.1	6.3%	383.1	7.6%	270.3	5.4%	288.8	5.7%	5043.3
2026	2210.3	42.7%	807.3	15.6%	355.1	6.9%	543.6	10.5%	319.4	6.2%	384.1	7.4%	270.4	5.2%	283.3	5.5%	5173.6
2027	2300.0	43.5%	819.6	15.5%	363.3	6.9%	547.1	10.4%	320.7	6.1%	385.1	7.3%	270.6	5.1%	277.7	5.3%	5284.2
2028	2403.6	44.4%	832.3	15.4%	373.0	6.9%	550.9	10.2%	322.0	6.0%	386.5	7.1%	270.8	5.0%	270.7	5.0%	5409.7
2029	2456.4	44.8%	845.3	15.4%	381.7	7.0%	554.6	10.1%	323.2	5.9%	387.9	7.1%	271.0	4.9%	264.1	4.8%	5484.1
2030	2516.8	45.2%	858.6	15.4%	390.6	7.0%	558.3	10.0%	324.4	5.8%	389.3	7.0%	271.2	4.9%	255.3	4.6%	5564.5

WINTER Peak Demand (MW)

	ND	%	SD	%	MN	%	IA	%	NE	%	MT	%	CO	%	WY	%	BEPC TOTAL
95/96	325.8	29.4%	309.0	27.9%	51.2	4.6%	88.9	8.0%	33.3	3.0%	31.6	2.9%	77.4	7.0%	189.9	17.2%	1107.0
96/97	334.5	29.3%	302.7	26.6%	47.9	4.2%	98.5	8.6%	35.7	3.1%	30.2	2.6%	79.8	7.0%	210.7	18.5%	1140.0
97/98	324.0	30.5%	263.3	24.8%	42.2	4.0%	77.5	7.3%	35.8	3.4%	29.3	2.8%	83.5	7.9%	207.9	19.6%	1063.4
98/99	331.3	29.2%	291.8	25.8%	47.8	4.2%	109.2	9.6%	37.0	3.3%	30.4	2.7%	84.3	7.4%	201.2	17.8%	1133.1
99/00	312.3	28.8%	269.3	24.8%	47.9	4.4%	102.3	9.4%	31.0	2.9%	28.0	2.6%	83.9	7.7%	209.0	19.3%	1083.8
00/01	342.1	27.4%	328.0	26.2%	57.4	4.6%	124.6	10.0%	42.5	3.4%	33.6	2.7%	83.2	6.7%	238.7	19.1%	1250.0
01/02	312.5	26.2%	300.4	25.2%	47.1	3.9%	108.4	9.1%	37.4	3.1%	34.9	2.9%	82.4	6.9%	270.3	22.6%	1193.4
02/03	376.7	27.7%	342.3	25.1%	54.0	4.0%	127.8	9.4%	35.7	2.6%	55.0	4.0%	103.1	7.6%	267.5	19.6%	1362.2
03/04	416.9	27.5%	393.8	25.9%	59.7	3.9%	134.2	8.8%	35.6	2.3%	62.4	4.1%	122.5	8.1%	293.2	19.3%	1518.4
04/05	437.9	27.4%	416.6	26.1%	62.7	3.9%	138.7	8.7%	43.5	2.7%	64.0	4.0%	121.2	7.6%	314.4	19.7%	1598.9
05/06	462.6	26.8%	414.7	24.0%	65.8	3.8%	186.6	10.8%	48.4	2.8%	72.2	4.2%	120.8	7.0%	353.4	20.5%	1724.6
06/07	494.6	25.4%	484.4	24.9%	111.0	5.7%	211.5	10.9%	50.0	2.6%	70.6	3.6%	121.8	6.3%	402.6	20.7%	1946.4
07/08	562.7	26.3%	524.3	24.5%	113.3	5.3%	231.7	10.8%	50.0	2.3%	80.7	3.8%	123.5	5.8%	454.0	21.2%	2140.2
08/09	622.7	25.7%	633.9	26.2%	133.3	5.5%	276.1	11.4%	56.5	2.3%	78.3	3.2%	137.8	5.7%	481.0	19.9%	2419.5
09/10	627.3	23.5%	618.6	23.2%	169.0	6.3%	517.7	19.4%	58.8	2.2%	73.6	2.8%	137.2	5.1%	468.4	17.5%	2670.6
10/11	678.7	25.2%	621.6	23.0%	197.7	7.3%	468.3	17.4%	54.5	2.0%	55.5	2.1%	144.9	5.4%	476.7	17.7%	2697.7
11/12	834.7	29.5%	599.9	21.2%	180.5	6.4%	442.5	15.6%	49.3	1.7%	91.5	3.2%	179.9	6.4%	449.7	15.9%	2828.1
12/13	972.6	32.3%	626.7	20.8%	193.8	6.4%	457.0	15.2%	52.4	1.7%	100.6	3.3%	182.8	6.1%	428.3	14.2%	3014.2
13/14	1134.3	31.9%	777.8	21.9%	252.6	7.1%	523.1	14.7%	54.2	1.5%	183.1	5.1%	199.9	5.6%	433.9	12.2%	3558.9
14/15	1358.8	37.2%	699.7	19.2%	232.9	6.4%	495.7	13.6%	56.6	1.6%	190.9	5.2%	184.4	5.1%	432.3	11.8%	3651.3
15/16	1394.3	39.9%	634.4	18.2%	228.5	6.5%	466.0	13.3%	53.6	1.5%	160.5	4.6%	184.2	5.3%	369.2	10.6%	3490.7
16/17	1441.3	38.7%	694.5	18.7%	248.8	6.7%	476.5	12.8%	52.9	1.4%	241.9	6.5%	184.3	5.0%	380.0	10.2%	3720.1
17/18	1545.5	39.3%	718.0	18.3%	281.3	7.2%	493.2	12.6%	56.7	1.4%	244.7	6.2%	191.3	4.9%	354.0	9.0%	3929.3
18/19	1717.1	42.3%	740.9	18.2%	288.9	7.1%	516.8	12.7%	48.2	1.2%	236.0	5.8%	193.9	4.8%	318.2	7.8%	4060.0
19/20	1956.1	45.0%	721.8	16.6%	283.4	6.5%	535.2	12.3%	56.6	1.3%	265.7	6.1%	198.5	4.6%	333.7	7.7%	4350.9
20/21	1885.5	44.2%	733.4	17.2%	291.9	6.8%	522.2	12.2%	55.2	1.3%	273.8	6.4%	194.7	4.6%	313.0	7.3%	4269.7
21/22	1968.5	44.2%	748.9	16.8%	310.8	7.0%	547.1	12.3%	57.6	1.3%	267.3	6.0%	198.8	4.5%	353.2	7.9%	4452.1
22/23	2182.8	45.3%	828.7	17.2%	318.4	6.6%	554.9	11.5%	58.1	1.2%	327.5	6.8%	198.9	4.1%	346.8	7.2%	4816.1
23/24	2331.3	46.1%	872.3	17.3%	318.5	6.3%	559.3	11.1%	58.7	1.2%	372.7	7.4%	199.1	3.9%	343.2	6.8%	5055.2
24/25	2514.0	47.4%	907.5	17.1%	327.2	6.2%	564.0	10.6%	59.2	1.1%	388.5	7.3%	199.3	3.8%	340.2	6.4%	5300.1
25/26	2649.6	48.4%	920.4	16.8%	357.2	6.5%	567.6	10.4%	59.8	1.1%	391.9	7.2%	199.4	3.6%	333.9	6.1%	5479.9
26/27	2755.3	49.1%	934.3	16.7%	364.2	6.5%	572.4	10.2%	60.3	1.1%	392.9	7.0%	199.6	3.6%	327.3	5.8%	5606.4
27/28	2865.1	49.9%	948.6	16.5%	372.3	6.5%	576.8	10.1%	60.9	1.1%	394.3	6.9%	199.8	3.5%	318.9	5.6%	5736.7
28/29	2935.5	50.4%	963.4	16.5%	379.7	6.5%	581.2	10.0%	61.5	1.1%	395.8	6.8%	200.0	3.4%	310.9	5.3%	5828.0
29/30	3009.1	50.8%	978.3	16.5%	387.3	6.5%	585.1	9.9%	62.1	1.0%	397.3	6.7%	200.2	3.4%	299.7	5.1%	5919.1

EXHIBIT 3 - EASTERN SYSTEM SUMMER/WINTER LOAD RESOURCES

	SPP SUMMER SEASON			
	Members' Load Projections*	Contracted Sales to Others	Losses & Diversity	Total Responsibility
2020	2,780	176	468	3,424
2021	2,892	137	488	3,517
2022	3,134	138	528	3,800
2023	3,477	137	584	4,198
2024	3,671	138	617	4,425
2025	3,782	137	635	4,554
2026	3,879	138	651	4,667
2027	3,982	137	668	4,786
2028	4,099	138	687	4,924
2029	4,168	137	698	5,003
2030	4,244	138	711	5,092

	SPP WINTER SEASON			
	Members' Load Projections*	Contracted Sales to Others	Losses & Diversity	Total Responsibility
2020/21	3,164	176	504	3,844
2021/22	3,282	138	525	3,945
2022/23	3,617	138	580	4,334
2023/24	3,835	138	616	4,588
2024/25	4,064	138	653	4,855
2025/26	4,216	138	678	5,032
2026/27	4,339	138	699	5,175
2027/28	4,466	138	720	5,323
2028/29	4,555	138	734	5,427
2029/30	4,647	138	749	5,534

	MISO Z1 SUMMER SEASON			
	Members' Load Projections*	Contracted Sales to Others	Losses & Diversity	Total Responsibility
2020	220	0	23	242
2021	239	0	25	264
2022	247	0	26	273
2023	254	0	27	282
2024	263	0	28	291
2025	272	0	29	301
2026	286	0	31	317
2027	293	0	32	325
2028	302	0	33	335
2029	309	0	34	343
2030	317	0	34	351

	MISO Z1 WINTER SEASON			
	Members' Load Projections*	Contracted Sales to Others	Losses & Diversity	Total Responsibility
2020/21	287	0	30	317
2021/22	294	0	31	325
2022/23	301	0	32	333
2023/24	304	0	32	336
2024/25	312	0	34	346
2025/26	325	0	35	360
2026/27	331	0	36	368
2027/28	339	0	37	376
2028/29	346	0	38	384
2029/30	353	0	38	391

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

2020 Resources

	Summer Season																				
	SPP																				MISO Z1
	LOS	LRS East	AVS[1]	Neal4	WS[2]	Wisdom1	Wisdom2	SMS	GGS	CGS	DCS	PGS	LCS	Madison	Webster City	Estherville	Spencer	Wind	Waste Heat	Solar	Purchases	Purchases
2020	660.0	92.0	900.0	104.0	72.0	36.3	65.0	99.6	172.2	85.5	297.0	235.3	206.2	10.0	21.0	9.3	10.0	230.7	24.5	-	223.5	300.0
2021	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	206.2	10.0	21.0	9.3	10.0	260.7	24.5	-	381.3	350.0
2022	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	259.6	24.5	-	430.3	325.0
2023	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	280.8	24.5	62.5	429.5	325.0
2024	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	280.8	24.5	137.5	277.7	325.0
2025	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	280.8	24.5	137.5	276.7	255.0
2026	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	280.8	24.5	137.5	275.9	255.0
2027	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	280.8	24.5	137.5	275.2	255.0
2028	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	280.8	24.5	137.5	274.5	75.0
2029	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	271.3	24.5	137.5	253.9	75.0
2030	660.0	92.0	900.0	104.0	-	36.3	65.0	99.6	172.2	85.5	297.0	235.3	246.2	10.0	21.0	9.3	10.0	271.0	24.5	137.5	253.2	75.0

	Winter Season																				
	SPP																				MISO Z1
	LOS	LRS East	AVS[1]	Neal4	WS[2]	Wisdom1	Wisdom2	SMS	GGS	CGS	DCS	PGS	LCS	Madison	Webster City	Estherville	Spencer	Wind	Waste Heat	Solar	Purchases	Purchases
2020/21	660.0	92.0	900.0	104.0	72.1	37.9	75.0	120.0	190.0	95.0	297.7	240.5	225.0	10.0	25.6	9.3	10.0	714.2	27.1	-	255.3	300.0
2021/22	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	714.2	27.1	-	380.3	350.0
2022/23	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	754.6	27.1	12.5	429.5	325.0
2023/24	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	754.8	27.1	27.5	428.7	325.0
2024/25	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	754.8	27.1	27.5	276.7	325.0
2025/26	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	754.8	27.1	27.5	275.9	255.0
2026/27	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	754.8	27.1	27.5	275.2	255.0
2027/28	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	754.8	27.1	27.5	274.5	255.0
2028/29	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	717.8	27.1	27.5	253.9	75.0
2029/30	660.0	92.0	900.0	104.0	-	37.9	75.0	120.0	190.0	95.0	297.7	240.5	270.0	10.0	25.6	9.3	10.0	715.7	27.1	27.5	253.2	75.0

Footnotes:

1) BEPC owns 24.166% of AVS unit 2 and leases the remaining portion from other owners. The term of the lease, currently stated to end on 12/30/2020, is being extended by 10 years through 2030.

2) WS 3 & 4 were pseudo tied into SPP for the 2020/2021 planning year and Basin Electric plans to return them back to MISO Local Resource Zone 3 thereafter