NEBRASKA PUBLIC POWER DISTRICT

2020

FINANCIAL REPORT



TABLE OF CONTENTS

Vision

Enhancing the quality of life for Nebraskans, through public power, now and in the future.

Mission

Safely generate and deliver reliable, low-cost, sustainable energy and related services, while providing outstanding customer service.

CORPORATE PROFILE

Nebraska Public Power District (NPPD), a public corporation and political subdivision of the State of Nebraska, operates an integrated electric utility system including generation, transmission and distribution facilities.

NPPD owns or has operating control of 31 generating facilities. This diverse power resource mix produces energy from a variety of fuel sources including coal, nuclear, natural gas, oil, hydro, wind and solar. NPPD operates 5,351 miles of transmission and subtransmission lines and 2,485 miles of distribution lines.

Revenues are primarily derived from wholesale power supply agreements with 46 municipalities and 24 public power districts and/or cooperatives. NPPD also serves more than 92,000 residential, commercial and industrial customers in 79 Nebraska communities at retail.

Formed by a merger on January 1, 1970, NPPD works in partnership with other utilities, businesses and community leaders to help serve more than 600,000 Nebraskans with retail or wholesale electric power and energy-related services.

Contol of NPPD and its operations is vested in an 11-member Board of Directors, popularly elected from within NPPD's chartered territory, including all or parts of 86 of Nebraska's 93 counties.

BY THE NUMBERS

Generating Facilities
31

Transmission and Subtransmission Lines
5,351 miles

Distribution Lines
2,485 miles

Wholesale Power Supply Agreements
46 Municipalities
24 Public Power Districts

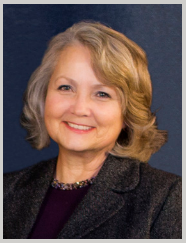
Residential, Commercial and Industrial Customers
92,000

Retail Communities
79

Works in Partnership with other Utilities to Serve More Than
600,000 Nebraskans

NPPD's Chartered Territory
86 of Nebraska's 93 counties

BOARD OF DIRECTORS



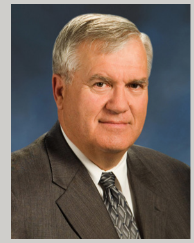
Mary A. Harding
Plattsmouth
Subdivision 1

Barry D. DeKay
Niobrara
Subdivision 2

Melissa S. Freelend
Kearney
Subdivision 3

Bill C. Hoyt
McCook
Subdivision 4

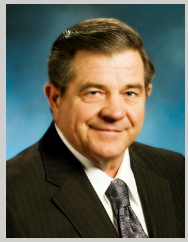
Charlie C. Kennedy
Scottsbluff
Subdivision 5



Edward J. Schrock
Holdrege/Elm Creek
Subdivision 6

Ken Kunze
York
Subdivision 7

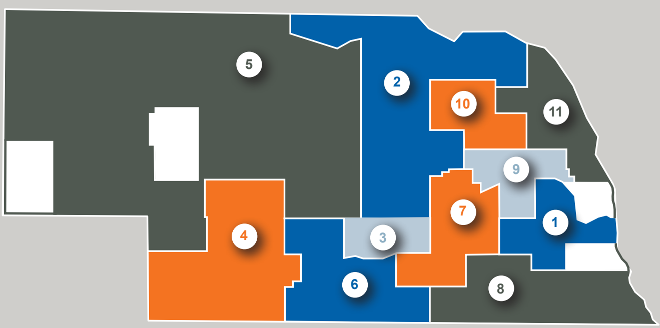
Gary G. Thompson
Clatonia
Subdivision 8

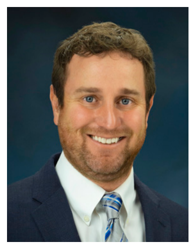


Jerry L. Chlopek
Columbus
Subdivision 9

William D. Johnson
Pilger
Subdivision 10

Fred L. Christensen
Lyons
Subdivision 11





Aaron Troester
2021 Board Member
(Elected in November 2020)
Subdivision 2

Wayne Williams
2021 Board Member
(Elected in November 2020)
Subdivision 7

SENIOR MANAGEMENT TEAM

Thomas J. Kent (1)
President &
Chief Executive Officer

Patrick L. Pope (1)
President &
Chief Executive Officer

Timothy J. Arlt
Vice President,
Corporate Strategy &
Innovation

Traci L. Bender
Executive Vice President,
Chief Financial Officer
& Treasurer

Kendall B. Curry
Vice President,
Customer Services &
Chief Customer Officer

John A. Dent, Jr.
Vice President,
Nuclear & Chief Nuclear
Officer

John C. McClure
Executive Vice President,
Governmental Affairs
& General Counsel

Michael J. Spencer
Vice President,
Energy Production

Robyn A. Tweedy
Vice President,
Enterprise Technology &
Chief Information Officer

Arthur R. Wiese
Vice President,
Energy Delivery

(1) Mr. Pope served as President and Chief Executive Officer through April 2020 before stepping down to serve as a Special Assistant. He was replaced in the position of President and CEO by Mr. Kent, who previously served as Vice-President and Chief Operating Officer.

A Message

FROM OUR 2020 BOARD CHAIRMAN
and CHIEF EXECUTIVE OFFICER

Barry D. DeKay
2020 Board Chairman

Thomas J. Kent
President & CEO

CHALLENGES AND CHANGE

"The best-laid plans of mice and men often go awry."

Irish poet Robert Burns inked those words in the 1700s, but little did he know what 2020 would be like as our best-laid plans met a challenge across the globe.

The year 2020 will long be remembered as a year of challenges and change. It was expected to be a celebratory year as Nebraska Public Power District planned to celebrate the 50-year anniversary of our formation and 50 years of service to Nebraskans. Instead, it was a year of hearing a word not commonly used: ***pandemic***.

COVID-19, also known as the coronavirus, was a monumental challenge felt not only in Nebraska, but across the world. Young and old alike were asked to change habits, stay home as much as possible, practice social distancing, wash hands often and wear masks to help slow the spread of the virus. Needless to say, our celebration was short-lived.

NPPD examined COVID-19's impacts on our workforce and customers. We took necessary precautions and safeguards to ensure continued reliable delivery of electricity for our customers and a workplace that was safe for our employees – with many having the ability to work from home. What was normally a workday at the office turned into a workday in a home office or other workspace, and normal face-to-face meetings became virtual.

During this pandemic, we learned a bit about ourselves, too. We learned that many of us were able to work successfully from home long-term, a concept we hadn't delved into much previously, and one that will likely continue long after the virus has run its course.

While 2020 had its diversions, we continued to focus on reliability and affordability for our customers. Operations continued as expected and our financial performance exceeded expectations (outlined in this report) despite being in a pandemic. We entered 2021 with no overall rate increase for our retail customers - for the eighth year in a row - and likewise for our wholesale customers for the fourth year in a row. In addition, we are providing a financial credit back to our customers through their bills for the third year in a row.

While we faced a different challenge than expected, it was also a time of transition for NPPD. In May, the Board of Directors appointed Thomas Kent as President and CEO to replace Pat Pope, who had served in that position since 2011, who stepped down but continues to focus on rural broadband issues for the District.

In spite of the many changes COVID-19 caused, we kept safety paramount. We established new records for consecutive days worked safely, achieved our lowest ever OSHA recordable figures, and were recognized as one of Nebraska's safest companies. We ranked first among peer utilities in safety by earning the American Public Power Association's 2020 Safety Award of Excellence.

We continue to have a strong carbon-free generation mix from our diverse generation of coal, nuclear, natural gas, hydro, wind and solar, serving our customers with 65% of their energy coming from carbon-free resources on a two-year rolling average basis. Our generating plants and transmission and distribution systems performed well throughout the year and Cooper Nuclear Station was given an excellent recognition by the Institute of Nuclear Power Operators organization. There continues to be interest in our "Community Solar" program and the state's largest solar array will come to Norfolk in 2021 which will include a battery-energy storage component.

With our Board and customers, we continue to look at decarbonization of NPPD's energy mix and managing business risk with an eye towards the future through our Carbon Business Risk Management initiative or what we will refer to as part of our "Powering our Future" initiative going forward.

Technology was at the forefront of our retail division. A three-year project was completed where more than 90,000 advanced metering infrastructure (AMI) meters were installed at homes and businesses in communities served at retail. Also introduced was a new "NPPD On the Go" app and web portal for retail customers allowing them to monitor their electric usage, outages, and billing via cell phone.

We were fortunate with the weather not causing any major disruptions on our system, but our crews responded to mutual aid restoration efforts in Iowa and Oklahoma, and we also lent a hand to some of our wholesale customers following an early season winter storm.

While we have faced change never anticipated, the challenge has been met in ways we did not foresee, while working from the kitchen table or wherever we might find ourselves working virtually. Through the resiliency of our teammates and customers, we met the challenges before us and continued our mission to safely generate and deliver reliable, low-cost, sustainable energy and provide outstanding customer service.

2020

FINANCIAL REPORT

NEBRASKA PUBLIC POWER DISTRICT




2020 YEAR AT A GLANCE

KILOWATT - HOUR SALES		18.9	BILLION
OPERATING REVENUES	$	1,103.1	MILLION
COST OF POWER PURCHASED AND GENERATED	$	581.4	MILLION
OTHER OPERATING EXPENSES	$	430.4	MILLION
INVESTMENT AND OTHER INCOME	$	51.6	MILLION
DEBT AND RELATED EXPENSES	$	47.0	MILLION
INCREASE IN NET POSITION	$	95.9	MILLION
DEBT SERVICE COVERAGE		1.89	TIMES

2020 STATISTICAL REVIEW (Unaudited)

THE CUSTOMERS – Classifications

OPERATING REVENUES	Average Cents Per kWh Sold Less Government Taxes/Transfers[1]	Average Cents Per kWh Sold	Average Number of Customers	MWh Amount	MWh %	Revenues (in 000's) Amount	Revenues (in 000's) %
Retail:							
Residential	10.34 ¢	12.35 ¢	72,846	856,151	4.5	$ 105,777	9.6
Commercial	8.26 ¢	9.71 ¢	19,362	1,080,545	5.7	104,926	9.5
Industrial	4.63 ¢	5.00 ¢	59	1,335,373	7.1	66,758	6.1
Total Retail Sales	7.32 ¢	8.48 ¢	92,267	3,272,069	17.3	277,461	25.2
Wholesale:							
Municipalities[2]		5.97 ¢	38	1,293,765	6.9	77,262	7.0
Municipalities (Partial Requirements)[3]		5.09 ¢	8	115,742	0.6	5,890	0.5
Public Power Districts and Cooperatives[2]		5.38 ¢	23	7,739,100	40.9	416,539	37.8
Public Power Districts (Part Req)[3]		4.61 ¢	1	27,849	0.1	1,283	0.1
Total Firm Wholesale Sales		5.46 ¢	70	9,176,456	48.5	500,974	45.4
Total Firm Retail and Wholesale Sales		6.25 ¢	92,337	12,448,525	65.8	778,435	70.6
Participation Sales		4.04 ¢	4	1,601,732	8.5	64,731	5.9
Other Sales[4]		2.19 ¢	1	4,853,854	25.7	106,312	9.6
Total Electric Energy Sales		5.02 ¢	92,342	18,904,111	100.0	949,478	86.1
Other Operating Revenues[5]						71,760	6.5
Unearned Revenues[6]						81,911	7.4
Total Operating Revenues						$ 1,103,149	100.0

COST OF POWER PURCHASED AND GENERATED	MWh Amount	MWh %	Costs (in 000's) Amount	Costs (in 000's) %
Production[7]	14,603,218	74.2	$ 413,181	71.1
Power Purchased	5,075,113	25.8	168,232	28.9
Total Production and Power Purchased	19,678,331	100.0	$ 581,413	100.0

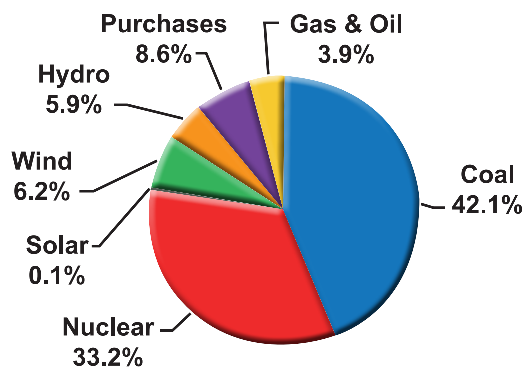
CONTRACTUAL AND TAX PAYMENTS (in 000's) [1]	Amount
Payments to Retail Communities	$ 28,252
Payments in Lieu of Taxes	9,795
Total Contractual and Tax Payments	$ 38,047

OTHER	Amount
Miles of Transmission and Subtransmission Lines in Service	5,351
Number of Full-Time Employees	1,904

(1) Customer collections for taxes/transfers to other governments are excluded from base rates.
(2) Sales are total requirements, subject to certain exceptions.
(3) Sales are to customers who limited their requirements under the 2002 Contracts. The average rate was lower than total requirements customers due to the exclusion of certain transmission costs from the wholesale rate as cost recovery was through the Southwest Power Pool ("SPP") transmission tariff and included in Other Operating Revenues.
(4) Includes sales in SPP and nonfirm sales to other utilities.
(5) Includes revenues for transmission and other miscellaneous revenues.
(6) Unearned revenues represent the net of revenue adjustments in the rate stabilization and other regulatory accounts, consistent with revenue requirements. Detailed information on unearned revenues is available in the Management's Discussion and Analysis.
(7) Includes fuel, operation, and maintenance costs. Debt service and capital-related costs are excluded.

SOURCES OF THE DISTRICT'S ENERGY SUPPLY (% OF MWH)

This chart shows the sources of energy for sales, excluding participation sales to other utilities. Purchases were included in the appropriate source, except for those purchases for which the source was not known.



MANAGEMENT'S DISCUSSION AND ANALYSIS (Unaudited)

The financial report for the Nebraska Public Power District ("District") includes Management's Discussion and Analysis, Financial Statements, Notes to Financial Statements, and Supplemental Schedules. The financial statements consist of the Statements of Net Position, Statements of Revenues, Expenses, and Changes in Net Position, Statements of Cash Flows, and Supplemental Schedules.

The following Management's Discussion and Analysis ("MD&A") provides unaudited information and analyses of activities and events related to the District's financial position or results of operations. The MD&A should be read in conjunction with the audited Financial Statements and Notes to Financial Statements.

The Statements of Net Position present assets, deferred outflows of resources, liabilities, deferred inflows of resources and net position as of December 31, 2020 and 2019. The Statements of Revenues, Expenses, and Changes in Net Position present the operating results for the years 2020 and 2019. The Statements of Cash Flows present the sources and uses of cash and cash equivalents for the years 2020 and 2019. The Notes to Financial Statements are an integral part of the basic financial statements and contain information for a more complete understanding of the financial position as of December 31, 2020 and 2019, and the results of operations for the years 2020 and 2019. The Supplemental Schedules include unaudited information required to accompany the Financial Statements.

OVERVIEW OF BUSINESS

The District is a public corporation and political subdivision of the State of Nebraska (the "State"). Control of the District and its operations is vested in a Board of Directors ("Board") consisting of 11 members popularly elected from districts comprising subdivisions of the District's chartered territory.

The District's chartered territory includes all or parts of 86 of the State's 93 counties and more than 400 municipalities in the State. The right to vote for the Board is generally limited to retail and wholesale customers receiving more than 50% of their annual energy from the District.

The District operates an integrated electric utility system including facilities for generation, transmission, and distribution of electric power and energy for sales at wholesale and retail. Management and operation of the District is accomplished with a staff of 1,904 full-time employees as of December 31, 2020. The District has the power, among other things, to acquire, construct, and operate generating plants, transmission lines, substations, and distribution systems and to purchase, generate, distribute, transmit, and sell electric energy for all purposes. There are no investor-owned utilities providing retail electric service in Nebraska.

The District has no power of taxation, and no governmental authority has the power to levy or collect taxes to pay, in whole or in part, any indebtedness or obligation of or incurred by the District or upon which the District may be liable. The District has the right of eminent domain. The property of the District, in the opinion of its General Counsel, is exempt under the State Constitution from taxation by the State and its subdivisions, but the District is required by the State to make payments in lieu of taxes which are distributed to the State and various governmental subdivisions.

The District has the power and is required to fix, establish, and collect adequate rates and other charges for electrical energy and any and all commodities or services sold or furnished by it. Such rates and charges must be fair, reasonable, and nondiscriminatory and adjusted in a fair and equitable manner to confer upon and distribute among the users and consumers of such commodities and services the benefits of a successful and profitable operation and conduct of the business of the District.

THE SYSTEM

To meet the estimated anytime peak load in 2020 of 2,797.3 megawatts ("MW"), the District had available 3,631.3 MW of capacity resources that included 3,024.2 MW of generation capacity from 11 owned and operated generating plants and 20 plants over which the District has operating control, 443.5 MW of firm capacity purchases from the Western Area Power Administration ("Western"), and 163.6 MW of a capacity purchase from Omaha Public Power District's ("OPPD") Nebraska City Station Unit No. 2 ("NC2") coal-fired plant. Of the total capacity resources, 366.0 MW are being sold via participation sales or other capacity sales agreements, leaving 3,265.3 MW to serve firm retail and wholesale customers and to meet capacity reserve requirements. The highest summer anytime peak load of 3,030.3 MW was established in July 2012 and the highest winter anytime peak load of 2,252.0 MW was established in January 2014 for firm requirements customers.

The following table shows the District's capacity resources from generation and respective summer 2020 accredited capability.

CAPACITY RESOURCES

Type	Number of Plants[(1)]	Summer 2020 Accredited Capability (MW)[(2)]	Percent of Total
Steam - Conventional[(3)]	3	1,683.3	55.7
Steam - Nuclear	1	770.0	25.4
Hydro[(4)]	5	109.5	3.6
Diesel	10	69.1	2.3
Combustion Turbine[(5)]	3	102.9	3.4
Combined Cycle	1	220.0	7.3
Wind[(6)]	8	69.4	2.3
	31	3,024.2	100.0

(1) Includes one hydro plant and ten diesel plants under contract to the District.
(2) Accreditation by SPP for the summer season 2020, pursuant to standard performance tests conducted by the District. Pursuant to agreements with other utilities, a portion of the accredited capability of certain generating plants has been sold to such utilities.
(3) Includes Gerald Gentleman Station ("GGS"), Sheldon Station ("Sheldon"), and Canaday Station.
(4) The increase in the number of hydro plants was due to the two hydro plants owned by Loup River Public Power District ("Loup"), which were severely damaged in March 2019 as a result of extreme adverse weather conditions. These two hydro plants returned to service during 2020.
(5) Includes the Hallam, Hebron, and McCook peaking turbines.
(6) Includes Ainsworth Wind Energy Facility ("Ainsworth") and seven wind facilities under contract to the District.

The following table shows the percentages of the District's energy supply produced from various sources and purchased, excluding energy produced with respect to Participation Sales and Other Sales, in each of the five years 2016 through 2020.

SOURCES OF THE DISTRICT'S ENERGY SUPPLY
(% of MWh)

Year	Coal[(1)]	Nuclear	Hydro[(2)]	Wind[(3)]	Gas and Oil	Purchases[(4)]	Solar[(5)]
2016	48.0	32.3	6.8	6.9	1.5	4.5	
2017	45.3	36.5	6.3	6.3	1.5	4.1	
2018	52.6	28.5	5.9	6.0	2.3	4.6	0.1
2019	46.6	34.2	5.2	5.4	3.3	5.2	0.1
2020	42.1	33.2	5.9	6.2	3.9	8.6	0.1

(1) Includes NC2.
(2) Includes hydro purchases from Loup, over which the District has operating control, and Western.
(3) Includes Ainsworth, Elkhorn Ridge Wind Facility, which began commercial operation in March 2009, Laredo Ridge Wind Facility, which began commercial operation in February 2011, Springview II Wind Energy Facility, which began commercial operation in August 2011, Crofton Bluffs Wind Facility, which began commercial operation in November 2012, Broken Bow I Wind Facility, which began commercial operation in December 2012, Steele Flats Wind Facility, which began commercial operation in November 2013, and Broken Bow II Wind Facility, which began commercial operation in October 2014.
(4) These are primarily purchases from SPP and JEA through 2019. In 2020, these are primarily purchases from SPP, as the JEA contract terminated on December 31, 2019. The increase in 2020 over 2019 was due primarily to additional energy purchases from the SPP Integrated Market as a result of a forced outage in August 2020 at GGS.
(5) Includes solar power purchases from solar retail Qualifying Local Generation.

The following table shows the generation facilities owned by the District and their respective fuel types, summer 2020 accredited capability, and in-service dates.

DISTRICT-OWNED GENERATION FACILITIES

Facility	Fuel Type	Summer 2020 Accredited Capability (MW) (1)	In-Service Date
Gerald Gentleman Station Units No. 1 and No. 2	Coal	1,365.0	1979, 1982
Cooper Nuclear Station	Nuclear	770.0	1974
Beatrice Power Station	Combined Cycle	220.0	2005
Sheldon Station Units No. 1 and No. 2	Coal	219.0	1961, 1968
Combustion Turbines (3 generating plants)	Oil or Natural Gas	102.9	1973
Canaday Station	Natural Gas	99.3	1958
Hydro (2 generating plants)	Water	24.0	1887, 1939
Ainsworth Wind Energy Facility(2)	Wind	5.1	2005
		2,805.3	

(1) 2020 summer accredited net capability based on SPP criteria.
(2) Nominally rated at 60 MW.

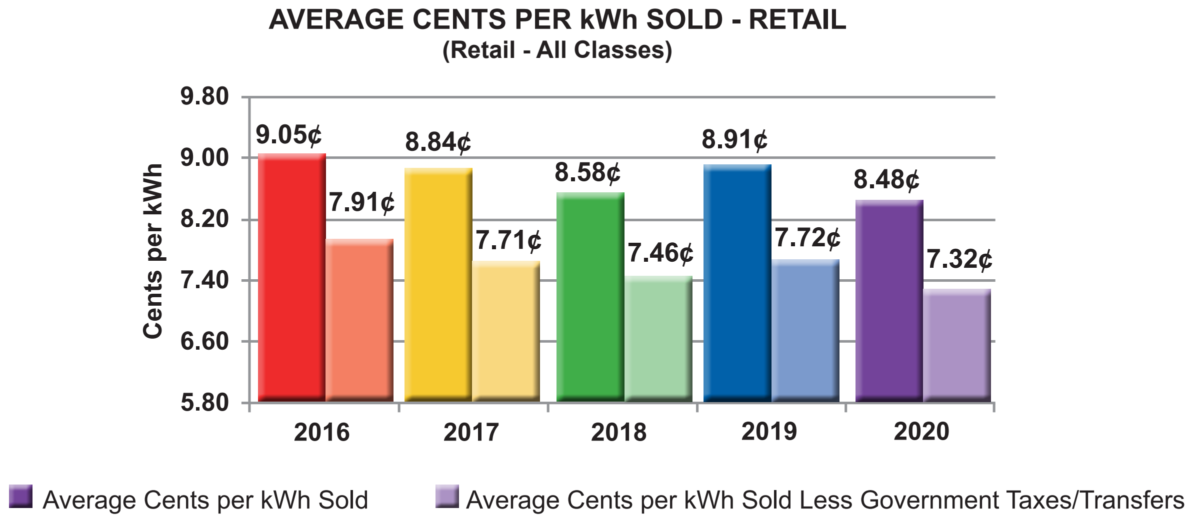
THE CUSTOMERS

Retail and Wholesale Customers

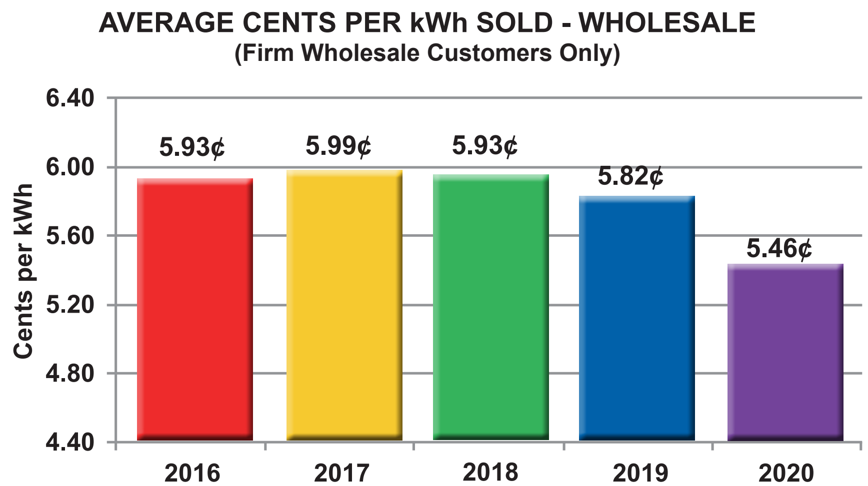
In 2020, the District served an average of 92,267 retail customers. The District's retail service territory includes 79 municipal-owned distribution systems operated by the District for the municipality pursuant to a Professional Retail Operations ("PRO") Agreement. Details of the District's PRO Agreements are included in Note 12 in the Notes to Financial Statements.

The District serves its wholesale customers under total requirements contracts that require them to purchase total power and energy requirements from the District, subject to certain exceptions. In 2016, the District entered into 20-year wholesale power sales contracts with a substantial number of its wholesale customers (the "2016 Contracts"). The 2016 Contracts replaced wholesale contracts that were entered into in 2002 (the "2002 Contracts"). Wholesale customers served under the 2016 Contracts include 22 public power districts, one cooperative and 37 municipalities. Nineteen of the public power districts and the one cooperative are served under one contract with the Nebraska Generation and Transmission Cooperative. Wholesale customers served under the 2002 Contracts include one public power district and nine municipalities. The 2016 Contracts allow a wholesale customer to reduce its demand and energy purchases from the District if the District's average annual wholesale power costs percentile level for a given year is higher than the 45th percentile level (the "Performance Standard Percentile") of the power costs of U.S. utilities for such year as listed in the National Rural Utilities Cooperative Finance Corporation Key Ratio Trend Analysis (Ratio 88) ("the CFC Data"). The District's goal, with respect to the cost of wholesale service (production and transmission), is that such costs are among the lowest quartile (25th percentile or less) for cost per kilowatt-hour ("kWh") purchased, as published by the CFC Data. The District's wholesale power costs percentile was 29.5% for 2019, based on the latest available data. Details of the District's Wholesale Power Contracts are included in Note 12 in the Notes to Financial Statements.

The following chart shows the District's average retail cents per kWh for the years ended December 31, 2016 through 2020. The chart also shows average cents per kWh sold less customer collections for taxes and transfers to other governments, which are not included in the District's base rates for retail customers. The decrease in the average cents per kWh sold in 2020 from 2019 was due to an increase in industrial energy sales, which has the lowest rates of all of the retail customer classes, and the retail level of service share of the Production Cost Adjustment ("PCA") refund from the District's wholesale level of service.



The following chart shows the District's average wholesale cents per kWh for the years ended December 31, 2016 through 2020. The decrease in the average cents per kWh sold in 2020 from 2019 was due to the PCA refund and the increase in energy sales.



<u>Participation Sales and Other Sales</u>

There are participation sales agreements in place with other utilities for the sale of power and energy at wholesale from specific generating plants. Such sales are to the City of Lincoln, Nebraska ("Lincoln"), Municipal Energy Agency of Nebraska ("MEAN"), OPPD, and Grand Island Utilities ("Grand Island"). The District also sells energy on a nonfirm basis in SPP and through transactions executed with other utilities by The Energy Authority ("TEA"). There was a participation sales agreement with JEA for sales from Ainsworth from October 1, 2005 through December 31, 2019.

<u>Transmission Customers</u>

The District owns and operates 5,351 miles of transmission and subtransmission lines, encompassing nearly the entire State. The District became a transmission owning member of SPP, a regional transmission organization, in 2009. The District files a rate with SPP annually that provides for the recovery of all transmission revenue requirements associated with transmission facilities equal to or greater than 115 kV. SPP collects and reimburses the District for the use of the District's transmission facilities by entities other than the District's firm requirements customers and all transmission customers still served directly by the District through grandfathered Transmission Agreements.

<u>Customers, Energy Sales, and Revenues</u>

The following table shows customers, energy sales, and peak loads of the System, including participation sales, in each of the three years, 2018 through 2020.

			Megawatt-Hour Sales				Anytime Peak Load (MW)
Calendar Year	Average Number of Retail Customers	Wholesale Customers(1)	Native Load Sales(2)	Percentage Growth(4)	Total Sales (3)	Percentage Growth(4)	Busbar Native Load
2018	91,838	77	12,933,912	(1.0)	20,025,515	2.3	2,726.2
2019	91,663	77	12,168,971	(5.9)	20,609,031	2.9	2,603.1
2020	92,267	75	12,448,525	2.3	18,904,111	(8.3)	2,820.5

(1) For 2020, includes sales to firm wholesale customers, participation customers (Lincoln, MEAN, OPPD and Grand Island), and a yearly average of two nonfirm customers. The decrease in the average number of wholesale customers by two in 2020 from 2019 was due to the termination of the JEA contract as of December 31, 2019 and the renegotiation of the contract with Western which excluded Lower Missouri Interconnection Energy Sales for 2020.

(2) Native load sales include wholesale sales to total firm requirements customers and the responsibility of replacement power being procured by the District if the District's generating assets are not operating. Predominantly, native load customers are served under long-term total requirements contracts.

(3) Total sales from the System include sales to Lincoln from GGS; to MEAN, OPPD, and Grand Island from Ainsworth, which sales commenced October 1, 2005, and terminate on September 30, 2025; to OPPD, MEAN, Lincoln and Grand Island from Elkhorn Ridge Wind Facility, which sales commenced March 1, 2009, and terminate on February 28, 2029; to MEAN from GGS and Cooper Nuclear Station ("CNS"), which sale commenced January 1, 2011, and terminate on December 31, 2023; to MEAN, Lincoln and Grand Island from Laredo Ridge Wind Facility, which sales commenced February 1, 2011, and terminate on January 31, 2031; to OPPD, Lincoln and Grand Island from Broken Bow I Wind Facility, which sales commenced December 1, 2012, and terminate on November 30, 2032; to OPPD, Lincoln and MEAN from Crofton Bluffs Wind Facility, which sales commenced November 1, 2012, and terminate on October 31, 2032; and to OPPD from Broken Bow II Wind Facility which sales commenced October 1, 2014, and terminate on September 30, 2039.

(4) The decrease in percentage growth for total sales from 2019 to 2020 was due primarily to a decrease in nonfirm energy sales as a result of the CNS planned refueling and maintenance outage, other fossil station outages, and reduced generation due to lower market prices in the SPP Integrated Market. The increase in percentage growth for native load sales from 2019 to 2020 was due primarily to more cooling degree days in 2020 as compared to 2019, due to the hotter, drier summer. The increase in percentage growth for total sales from 2018 to 2019 was due primarily to additional nonfirm energy sales from CNS due to more generation in 2019 as there was a planned refueling and maintenance outage in 2018. The decrease in native load sales from 2018 to 2019 was due primarily to weather, additional reductions by customers under the 2002 Contracts and reductions for qualifying local generation as allowed under the 2016 Contracts. There were fewer heating and cooling degree days in 2019 as compared to 2018.

FINANCIAL INFORMATION

The following tables summarize the District's financial position and operating results.

CONDENSED BALANCE SHEETS (in 000's)

As of December 31,	2020	2019	2018
Current Assets	$ 884,104	$ 990,989	$ 924,108
Special Purpose Funds	824,572	770,592	727,607
Utility Plant, Net	2,571,381	2,532,806	2,562,556
Other Long-Term Assets	275,517	312,163	351,046
Deferred Outflows of Resources	101,751	294,168	333,343
Total Assets and Deferred Outflows	$ 4,657,325	$ 4,900,718	$ 4,898,660
Current Liabilities	$ 309,371	$ 293,862	$ 380,675
Long-Term Debt	1,345,408	1,482,409	1,506,605
Other Long-Term Liabilities	792,188	981,074	997,359
Deferred Inflows of Resources:			
Unearned Revenues	201,589	262,500	247,853
Other Deferred Inflows	254,552	222,548	197,027
Net Position	1,754,217	1,658,325	1,569,141
Total Liabilities, Deferred Inflows, and Net Position	$ 4,657,325	$ 4,900,718	$ 4,898,660

CONDENSED RESULTS OF OPERATIONS (in 000's)

For the years ended December 31,	2020	2019	2018
Operating Revenues	$ 1,103,149	$ 1,074,475	$ 1,144,858
Operating Expenses	(1,011,837)	(974,102)	(1,025,185)
Operating Income	91,312	100,373	119,673
Investment and Other Income	51,629	47,050	26,896
Debt and Related Expenses	(47,049)	(58,239)	(63,861)
Increase in Net Position	$ 95,892	$ 89,184	$ 82,708

SOURCES OF OPERATING REVENUES (in 000's)

For the years ended December 31,	2020	2019	2018
Firm Retail and Wholesale Sales	$ 778,435	$ 807,201	$ 857,075
Participation Sales	64,731	59,717	63,906
Other Sales	106,312	165,613	140,048
Other Operating Revenues	71,760	77,591	79,756
Unearned Revenues	81,911	(35,647)	4,073
Total Operating Revenues	$ 1,103,149	$ 1,074,475	$ 1,144,858

CONDENSED STATEMENTS OF CASH FLOWS (in 000's)

For the years ended December 31,	2020	2019	2018
Net Cash Provided by Operating Activities	$ 205,431	$ 358,025	$ 363,088
Net Cash Provided by (Used in) Investing Activities	128,242	(58,362)	(45,884)
Net Cash Used in Capital and Financing Activities	(326,151)	(308,920)	(319,506)
Net Increase (Decrease) in Cash and Cash Equivalents	7,522	(9,257)	(2,302)
Cash and Cash Equivalents, Beginning of Year	16,245	25,502	27,804
Cash and Cash Equivalents, End of Year	$ 23,767	$ 16,245	$ 25,502

The decrease in net cash provided by operating activities in 2020 was due primarily to the PCA customer refund and increased payments for Other Postemployment Benefits ("OPEB") and nuclear fuel.

Revenues from Firm Retail and Wholesale Sales

The District allocates costs between retail and wholesale service and establishes its rates to produce revenues sufficient to meet its estimated respective retail and wholesale revenue requirements. Wholesale revenue requirements include unbundled costs accounted for separately between generation and transmission. The rates for retail service include an amount to recover the costs of wholesale power service in addition to distribution costs and government taxes and transfers. The District's wholesale power contracts provide for the establishment of cost-based rates. Such rates can be adjusted at such times as deemed necessary by the District. The wholesale power contracts also provide for the creation of a rate stabilization account. Any surplus or deficiency between revenues and revenue requirements, within certain limits set forth in the wholesale power contracts, may be retained or withdrawn through the rate stabilization account. Any amounts in excess of the limits may be included as an adjustment to revenue requirements in the next rate review. The wholesale power contracts also include a provision for establishing a new/replacement generation fund. This provision would permit the District to collect an additional 0.5 mills per kWh above the normal revenue requirements to be used for future capital expenditures associated with generation.

There was no change to the wholesale and retail base rates for 2021, 2020 and 2019. However, a rate study was performed in 2020 and there were changes in individual demand and energy rates, effective February 1, 2021, as a result of the study. In addition, the District implemented a 12-month PCA rate to refund amounts to its wholesale customers for production rate stabilization funds in excess of the 10 percent accumulated limit. The refunds implemented on February 1, 2021, 2020, and 2019 amounted to $73.2 million, $46.1 million, and $26.8 million, respectively. The PCA equates to a one-year average bill reduction for wholesale customers of 10.2%, 6.2%, and 3.6%, for the respective 12-month periods beginning February 1, 2021, 2020, and 2019. The PCA also resulted in an average annual decrease for retail customers of 3.9%, 3.5%, and 3.5% for the respective 12-month periods beginning February 1, 2021, 2020, and 2019. Details of the District's Wholesale Power Contracts are included in Note 12 in the Notes to Financial Statements.

Revenues from firm sales decreased $28.8 million, or 3.6%, from $807.2 million in 2019 to $778.4 million in 2020. The decrease was due primarily to a larger refund to wholesale customers through the PCA rate (as referenced in the preceding paragraph), additional reductions by certain wholesale customers under the 2002 Contracts, additional reductions for qualifying local generation as allowed under the 2016 Contracts, and a COVID-19 pandemic-related decline in end-use sales to some customers. Revenues from firm sales decreased $49.9 million, or 5.8%, from $857.1 million in 2018 to $807.2 million in 2019. The decrease in revenues was due to several factors including the weather (as there were fewer heating and cooling degree days in 2019), the implementation of the PCA in 2019, additional energy requirements reductions from customers under the 2002 Contracts, reductions for qualifying local generation as allowed under the 2016 Contracts and the collection of transmission revenues for partial requirements customers through the SPP transmission tariff instead of the wholesale rate.

Revenues from Participation Sales

Revenues from participation sales increased from $59.7 million in 2019 to $64.7 million in 2020, an increase of $5.0 million. The increase was due to an increase in demand costs related to CNS and increased capacity sales. Revenues from participation sales decreased from $63.9 million in 2018 to $59.7 million in 2019, a reduction of $4.2 million. The reduction was due to a decrease in demand costs related to GGS and CNS in 2019.

Revenues from Other Sales

Other sales consist of sales in SPP's Integrated Market and nonfirm sales to other utilities. TEA, of which the District is a member, has energy marketing responsibilities for the District's other and nonfirm off-system sales and the related management of credit risks. Other sales decreased from $165.6 million in 2019 to $106.3 million in 2020, a decrease of $59.3 million. This decrease was due primarily to lower prices in the SPP Integrated Market and a decrease in energy sales due to the CNS planned refueling and maintenance outage and other fossil station outages. Other sales increased from $140.0 million in 2018 to $165.6 million in 2019, an increase of $25.6 million. The increase was a result of higher energy sales due to no refueling and maintenance outage at CNS.

Other Operating Revenues

Other operating revenues consist primarily of revenues for transmission and other miscellaneous revenues. These revenues were $71.8 million, $77.6 million, and $79.8 million in 2020, 2019, and 2018, respectively. The majority of these revenues were from SPP transmission customers. The decrease in each year is due primarily to lower SPP transmission revenues from customers for their share of qualifying transmission upgrade projects of the District. Such decreases are partially offset by additional SPP transmission revenues from wholesale customers who have become partial requirements customers under the 2002 Contracts, and must purchase transmission service through SPP.

Unearned Revenues

Under the provisions of the District's wholesale power contracts, any surplus or deficiency between net revenues and revenue requirements, within certain limits set forth in the wholesale power contracts, may be adjusted in the rate stabilization account. Any amounts in excess of the rate stabilization limits may be included as an adjustment to revenue requirements in the next rate review. A similar process is followed in accounting for any surplus or deficiency in revenues necessary to meet revenue requirements for retail electric service. Under generally accepted accounting principles for regulated electric utilities, the balance of such surpluses or deficiencies are accounted for as "regulatory liabilities or assets", respectively.

The District recognizes net revenues in excess of revenue requirements in any year as a deferral or reduction of revenues. Such surplus revenues are excluded from the net revenues available under the General Revenue Bond Resolution ("General Resolution") to meet debt service requirements for such year. Surplus revenues are included in the determination of net revenues available under the General Resolution to meet debt service requirements in the year that such surplus revenues are considered in setting rates. The District recognizes any deficiency in revenues needed to meet revenue requirements in any year as an accrual or increase in revenues, even though the revenue accrual will not be realized as "cash" until some future rate period. Such revenue deficiency is included, in the year accrued, in the net revenues available under the General Resolution to meet debt service requirements for such year. Revenue deficiencies are excluded in the determination of net revenues available under the General Resolution to meet debt service requirements in the year that such revenue deficit is considered in setting rates.

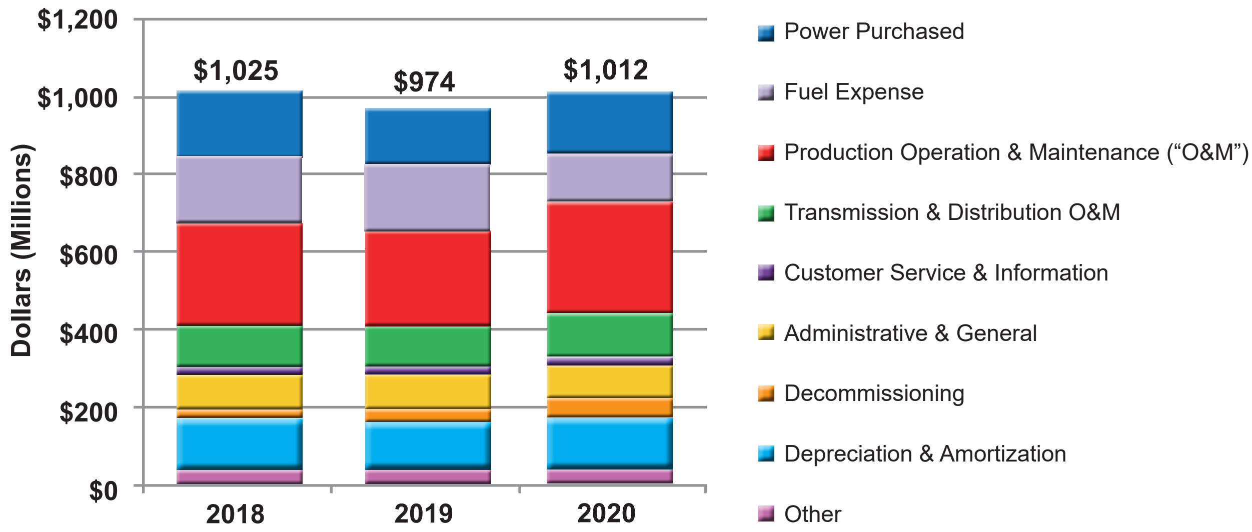
The following table shows the increase (decrease) in revenues from rate stabilization and other regulatory accounts for the years 2020, 2019 and 2018, respectively (in 000's).

	2020	2019	2018
Surplus revenues deferred to future periods	$ (14,883)	$ (71,292)	$ (70,006)
Refunded revenues from prior periods	75,794	56,645	29,080
CNS outage collections	21,000	(21,000)	20,005
OPEB deferred collections	-	-	23,500
Revenues from settlement agreements	-	-	1,493
	$ 81,911	$ (35,647)	$ 4,072

The balance of the regulatory liability for unearned revenues to be applied as credits against revenue requirements in future rate periods was $201.6 million, $262.5 million, and $247.9 million, as of December 31, 2020, 2019, and 2018, respectively.

Operating Expenses

The following chart illustrates operating expenses for the years ended December 31, 2018 through 2020.



Total operating expenses in 2020 were $1,011.8 million, an increase of $37.7 million from 2019. Total operating expenses in 2019 were $974.1 million, a decrease of $51.1 million from 2018. The changes were due primarily to the following:

Power purchased expenses were $168.2 million, $154.9 million and $161.7 million in 2020, 2019 and 2018, respectively. These expenses increased $13.3 million in 2020 over 2019 due primarily to additional energy purchases from the SPP Integrated Market and wind facilities, and a forced outage in August 2020 at GGS. These expenses decreased $6.8 million in 2019 from 2018 due primarily to fewer purchases from Loup, NC2, capacity towns and wind.

Fuel expenses were $141.6 million, $166.7 million and $174.7 million in 2020, 2019 and 2018, respectively. These expenses decreased $25.1 million in 2020 from 2019 due primarily to reduced generation at CNS due to the planned refueling and maintenance outage, GGS and Sheldon unplanned outages and low market prices. These expenses decreased $8.0 million in 2019 from 2018 due primarily to lower fuel costs at GGS and Sheldon.

Production operation and maintenance expenses were $271.6 million, $238.5 million, and $275.0 million in 2020, 2019, and 2018, respectively. These expenses increased $33.1 million in 2020 from 2019 due primarily to the planned refueling and maintenance outage at CNS in 2020. These costs decreased $36.5 million in 2019 from 2018 due primarily to the planned refueling and maintenance outage at CNS in 2018.

Transmission and distribution operation and maintenance expenses were $106.7 million, $104.4 million, and $105.2 million in 2020, 2019, and 2018, respectively. These costs increased $2.3 million in 2020 as compared to 2019 due primarily to additional expenses for maintenance and vegetation management. These costs decreased $0.8 million in 2019 as compared to 2018.

Customer service and information expenses were $16.1 million, $15.9 million, and $16.8 million in 2020, 2019, and 2018, respectively.

Administrative and general expenses were $90.7 million, $102.0 million, and $104.9 million in 2020, 2019, and 2018, respectively. These costs decreased $11.3 million in 2020 as compared to 2019 due primarily to a reduction in OPEB expenses, partially offset by an increase in salaries. These costs decreased $2.9 million in 2019 as compared to 2018. The decrease was due primarily to a reduction in OPEB expenses, which was partially offset by increased expenses for salaries and outside services and a lower amount of administrative and general expenses capitalized for construction projects.

Decommissioning expenses were $52.7 million, $28.5 million, and $15.7 million in 2020, 2019, and 2018, respectively. Decommissioning expenses are recorded in an amount equivalent to the income on investments for decommissioning plus amounts collected for decommissioning in the rates for electric service in such year. Decommissioning expenses increased $24.2 million in 2020 as compared to 2019 and $12.8 million in 2019 as compared to 2018 due primarily to an increase in investment income for decommissioning funds and additional expenses for non-nuclear assets.

Depreciation and amortization expenses were $126.2 million, $125.0 million, and $133.1 million in 2020, 2019, and 2018, respectively. The increase from 2019 to 2020 of $1.2 million was due primarily to the amortization of costs related to lease plant improvements for retail customers. The decrease from 2018 to 2019 of $8.1 million was due to several large assets related to GGS Unit No. 1 being fully depreciated. GGS Unit No. 1 was placed in service in 1979.

Investment and Other Income

Investment and other income were $51.6 million, $47.1 million and $26.9 million in 2020, 2019, and 2018, respectively. The increase of $4.5 million in 2020 as compared to 2019 was due primarily to increased investment income on decommissioning fund investments. The increase of $20.2 million in 2019 as compared to 2018 was due primarily to increased investment income on decommissioning fund investments and higher interest rates.

Debt and Related Expenses

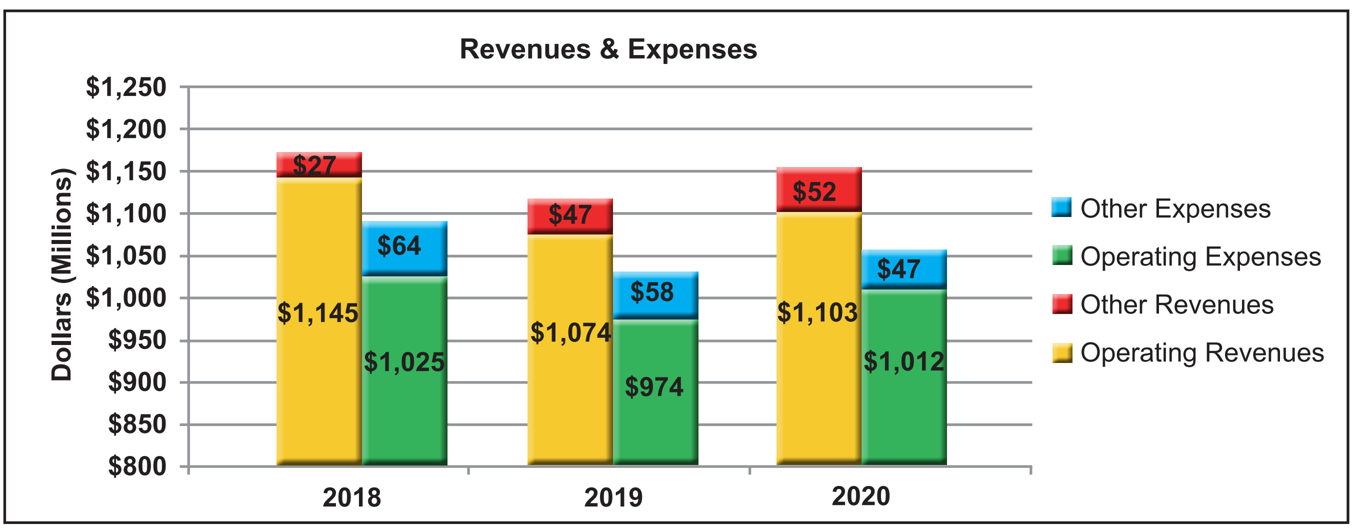
Debt and related expenses were $47.0 million, $58.2 million and $63.9 million in 2020, 2019 and 2018, respectively. The decrease of $11.2 million from 2019 to 2020 was due primarily to a reduction in the amount financed for nuclear fuel, lower interest rates, and lower outstanding principal balances. The decrease of $5.7 million from 2018 to 2019 was due primarily to a decrease in interest expense from fewer outstanding revenue bonds.

Increase in Net Position

The increase in net position was $95.9 million, $89.2 million, and $82.7 million in 2020, 2019, and 2018, respectively. The change in net position in 2020 as compared to 2019 increased $6.7 million and was due primarily to an increase in revenue collections for principal payments for debt service, which was partially offset by a decrease in revenue collections for capital projects, unrealized market gains on investments, and higher depreciation expense.

The change in net position in 2019 as compared to 2018 increased $6.5 million and was due primarily to an increase in revenue collections for capital projects, lower depreciation expense and an increase in unrealized market gains on investments, which was partially offset by a decrease in revenue collections for debt service.

The following chart illustrates the District's operating revenues, other revenues, operating expenses, and other expenses for the years ended December 31, 2018 through 2020.



FINANCIAL MANAGEMENT POLICY

The District has a Financial Management Policy (the "Policy"), which is subject to periodic review and revisions by the Board. This Policy represents general financial strategies and procedures that are implemented to demonstrate financial integrity and fiscal responsibility in the management of the District's business and its assets. Employees must abide by all applicable District bylaws, Board resolutions, bond resolutions, federal and state laws, other relevant legal requirements and the Policy.

DEBT SERVICE COVERAGE

Under the Policy, the District has established a minimum debt service coverage ratio on the General Revenue Bonds of 1.5 times the debt service on the General Revenue Bonds. Coverage is provided primarily by the amounts collected in operating revenues for utility plant additions, for principal and interest payments on outstanding revolving credit agreements and notes, and for payments to those municipalities served by the District under long-term PRO Agreements. The District's debt service coverage ratio was 1.89, 2.18, and 2.03 in 2020, 2019, and 2018, respectively. The debt service coverage was lower for 2020 than 2019, due primarily to the inclusion of the debt service on the General Revenue Bonds, 2010 Series C, redeemed in December 2020. The District prefers to show all debt service paid from revenues, including debt service on redeemed bonds, even though the General Resolution defines debt service only to include scheduled debt service. If the debt service on the said General Revenue Bonds so redeemed were excluded for 2020, the debt service coverage for 2020 was 2.36 times. The increase in the 2019 debt service coverage ratio over 2018 was primarily due to a decrease in the required debt service deposits. For additional detail, refer to the Calculation of Debt Service Ratios in the Supplemental Schedules.

FINANCING ACTIVITIES

Good credit ratings allow the District to borrow funds at more favorable interest rates. Such ratings reflect only the view of such rating organizations, and an explanation of the significance of such rating may be obtained only from the respective rating agency. There is no assurance that such ratings will be maintained for any given period of time or that they will not be revised downward or be withdrawn entirely by the respective rating agency if, in its judgment, circumstances so warrant. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market prices of bonds.

The District's credit ratings on its revenue bonds were as follows:

Moody's Investors Service	A1	(stable outlook)
Standard & Poor's Ratings Services	A+	(stable outlook)
Fitch Ratings	A+	(stable outlook)

The District plans, pursuant to the Policy, to issue separate series of indebtedness, including separate series of General Revenue Bonds, for production projects and for transmission projects. No more than 20.0% of the amount of outstanding indebtedness issued for production projects, calculated at the time of issuance of each series of such indebtedness, or $200.0 million, whichever is less, will be permitted to mature after January 1, 2036, the end of the 2016 Contracts. Transmission indebtedness issued for transmission projects is expected to mature over the useful life of the asset that is being financed. New transmission indebtedness may mature after January 1, 2036. The District's transmission indebtedness is payable from the revenues received during the term of the 2016 Contracts and from retail sales and transmission revenues received under various SPP tariffs. After January 1, 2036, transmission indebtedness will be payable from revenues to be derived from wholesale and retail customers who use the District's transmission facilities, as well as revenues from various SPP tariffs.

In November 2020, the District issued $125.8 million of General Revenue Bonds, 2020 Series A for the principal purpose of financing and refinancing the costs of construction of certain transmission facilities of the District.

In December 2020, the District redeemed $42.8 million of General Revenue Bonds, 2010 Series C.

The District has entered into a tax-exempt revolving credit agreement ("TERCA") with two commercial banks to provide for loan commitments to the District up to an aggregate amount not to exceed $150.0 million. The District's TERCA was renewed on October 15, 2020, with a termination date of October 13, 2023. See additional information about the District's TERCA in Note 7.

The District has entered into a taxable revolving credit agreement ("TRCA") with two commercial banks to provide for loan commitments to the District up to an aggregate amount not to exceed $200.0 million. The TRCA allows the District to increase the loan commitments to $300.0 million. The agreement currently has a termination date of July 29, 2021. The District expects to renew the TRCA for an additional three years. See additional information about the District's TRCA in Note 7.

In March 2021, the District initiated the preliminary closing on $75.5 million of General Revenue Bonds, 2021 Series A (Forward Delivery) at a premium of $17.3 million, and $52.1 million of General Revenues Bonds, 2021 Series B (Forward Delivery) at a premium of $12.9 million, for the principal purpose of refunding certain of the District's outstanding General Revenue Bonds, 2014 Series A, 2014 Series C, and 2015 Series A-2. The refunding was completed with $157.8 million of the proceeds from the General Revenue Bonds, 2021 Series A and B, and $1.1 million of other available funds. As a result, total debt service payments over the life of the bonds are expected to be reduced by $42.6 million, which will result in total present value savings of $31.0 million. The 2021 Series A and B Forward Delivery transaction has a settlement date of October 2021.

The District expects to continue to finance through 2024 from indebtedness a prior year SPP Notice to Construct capital project for approximately 225 miles of 345 kV transmission line (the "R-Project") which has an SPP approved estimated cost of $462.1 million. The District's current estimate for the cost of the construction of the R-Project, including escalation, is $473.1 million. The District previously issued General Revenue Bonds, 2020 Series A to finance a portion of the cost of the R-Project. The District has spent approximately $123.1 million through December 31, 2020, for design, construction mobilization and easement acquisitions.

In October 2019, the District issued $74.7 million of General Revenue Bonds, 2019 Series B-1 (Taxable) and $16.3 million of General Revenue Bonds, 2019 Series B-2 (Taxable) for the principal purpose of refunding certain of the District's outstanding General Revenue Bonds, 2012 Series A, 2014 Series A, 2014 Series C, and 2015 Series A-2. The refunding was completed with $91.0 million of the proceeds from the 2019 Series B-1 and B-2 General Revenue Bonds and $3.5 million of other available funds. As a result, total debt service payments over the life of the bonds were reduced by $9.9 million, which resulted in total present value savings of $6.0 million.

In January 2019, the District issued $36.0 million of General Revenue Bonds, 2019 Series A, at a premium of $5.2 million, to refund $50.4 million of General Revenue Bonds, 2009 Series A (Taxable Build America Bonds). The refunding was completed with $41.2 million of the proceeds from General Revenue Bonds, 2019 Series A, $3.7 million from the TERCA, and $5.5 million of other available funds. As a result, total debt service payments over the life of the bonds was reduced by $20.4 million, which resulted in present value savings of $6.6 million.

In January 2019, the District defeased certain of the General Revenue Bonds, 2017 Series A, with an outstanding principal amount that aggregated $7.3 million and called the remaining outstanding General Revenue Bonds, 2009 Series C, with a principal amount that aggregated $0.4 million.

Details of the District's debt balances and activity are included in Note 7 in the Notes to Financial Statements.

CAPITAL REQUIREMENTS

The Board-authorized capital projects totaled approximately $94.9 million, $154.5 million, and $85.5 million in 2020, 2019, and 2018, respectively. The District's capital requirements are funded with monies generated from operations, debt proceeds, and other available reserve funds.

Capital projects for 2020 included:

- $17.6 million for the Kearney Tech oNE transmission line and substation projects
- $11.4 million for a generator stator rewind at GGS Unit No. 2
- $3.6 million for a generator stator rewind at Beatrice Power Station

Capital projects for 2019 included:

- $53.1 million amendment resulting in a new project cost of $417.3 million for the R-Project, an SPP Notice to Construct project, for a high-voltage transmission line approved in prior years
- $9.8 million to replace a Superheat Intermediate Bank at GGS
- $9.4 million to replace Two-Way Automatic Communication System retail customer meters
- $6.1 million to upgrade System Control Board Map at the Doniphan Control Center
- $5.0 million for a reactor feeder pump turbine A overhaul at CNS

Capital projects for 2018 included:

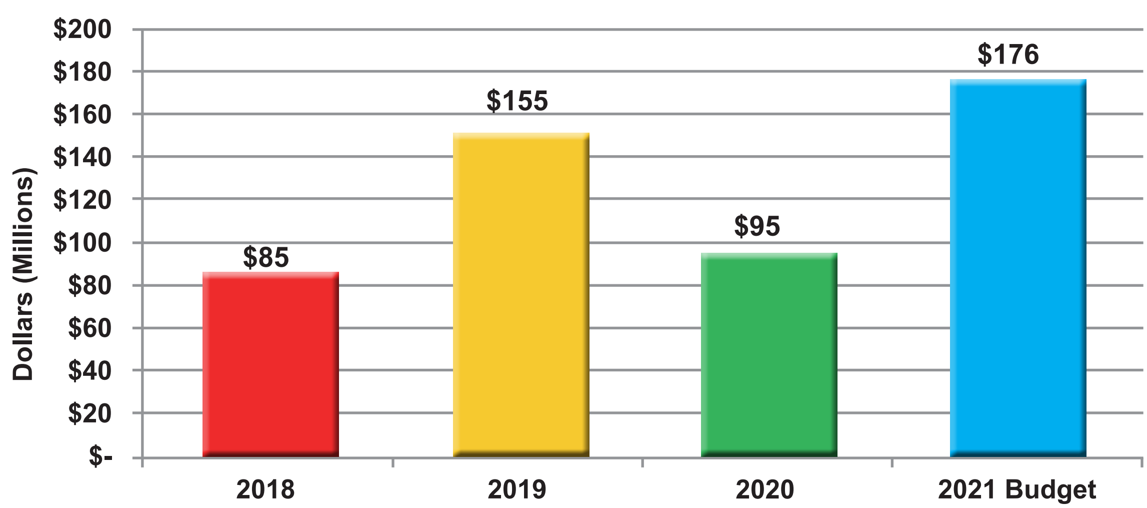
- $24.3 million for retrofit of the low-pressure turbine for GGS Unit No. 2
- $5.0 million for a south building addition for training and fleet at the Operations Center in York, Nebraska
- $4.5 million for refurbishment of the main generator exciter at CNS
- $4.4 million for a plant management information system at CNS
- $4.3 million for a reactor feed pump turbine B overhaul at CNS

There were other authorized capital projects for renewals and replacements to existing facilities and other additions and improvements of $62.3 million, $71.1 million, and $43.0 million for 2020, 2019, and 2018, respectively.

The Board-authorized budget for capital projects for 2021 is $176.2 million. Specific capital projects for 2021 include:

- $73.1 million for Monolith-related projects
- $10.7 million for SAP S4 HANA and SAP SAC Planning technical upgrades
- $5.3 million for Pauline to Mark Moore transmission line conductor replacement
- $5.0 million for Spencer Hydro retirement
- $4.7 CNS condenser pipe replacement

The following chart illustrates the Board-authorized capital projects for the years ended December 31, 2018 through 2020, including the Board-authorized budget for the year ended December 31, 2021.



TRANSMISSION LINE – THE R-PROJECT

The District received an SPP Notice to Construct for the R-Project, which allows the cost of construction to be included in SPP annual revenue requirements. The R-Project consists of the construction of approximately 225 miles of 345 kV transmission line from GGS, north to a new substation in Holt County interconnected to an existing 345 kV line owned by Western. The R-Project will strengthen the reliability of the District's transmission system, reduce transmission congestion, and allow for the integration of future renewable generation in an area of the state that lacks transmission access. The R-Project construction is currently delayed because of litigation which is discussed in the Endangered Species section of Note 12.

A bill has been introduced into the Nebraska Legislature that would impose a moratorium on any expenditures for commencing or continuing construction of a transmission line project for 200 miles or greater in length until January 1, 2023 and until all required federal permits are obtained. The bill also creates a special study committee to review various aspects of transmission line development, approval and impacts. The District cannot predict whether the legislation will be approved as introduced or in a modified form, but if passed, it would delay the R-Project and increase costs due to the delays. It is not possible to predict the extent of additional costs if this bill was passed.

In November 2020, SPP approved the estimated cost of the R-Project at $462.1 million. The estimated cost of the R-Project so approved by SPP became the new baseline for the R-Project. This estimate did not include any escalation of costs due to the two-year delay assumed by the District in developing its current estimated cost of construction of the R-Project. SPP will adjust the baseline for escalation on an annual basis. The District's current estimate for the cost of construction of the R-Project, including escalation, is $473.1 million, which includes costs for a two-year delay. The District awarded a contract for the construction of the R-Project in January 2019. The District has spent approximately $123.1 million through December 31, 2020, for design, construction mobilization and easement acquisitions.

FEBRUARY 2021 EXTREME WEATHER EVENT

There was an extreme weather event in February 2021 that impacted several states, including the area served by SPP as well as neighboring regional transmission organizations. Additional details are included in Note 14.

COVID-19 CORONAVIRUS PANDEMIC

On February 11, 2020, the World Health Organization announced the name for the outbreak of a new strain of coronavirus and the upper respiratory tract illness ("COVID-19") which has spread globally. COVID-19 was characterized as a pandemic by the World Health Organization and resulted in a declaration of a state of emergency by the President of the United States and the State of Nebraska since March 13, 2020. COVID-19 conditions throughout the District's wholesale and retail service areas have varied for 2020 and early 2021 with periods of increasing and decreasing rates of COVID-19 cases for both the public and District employees. The rural and agricultural nature of the District's wholesale and retail service areas has generally lessened the overall economic impacts compared to more urban areas of the state and nation.

There have been no significant operational impacts to the District as a result of COVID-19. Since the beginning of the pandemic through March 31, 2020, approximately 13 percent of District employees have tested positive for COVID-19. The District continues to safely and reliably generate and deliver energy to its customers. The District adjusted the scope of certain generation outages to mitigate risk for potential schedule impacts related to COVID-19. Field crews prioritized reliability work and provided updated work criteria to provide for social distancing, masks, and other protective actions. The District has not sequestered staff at any of its power generating stations or transmission and subtransmission operator control rooms but has made preparations to do so if necessary. The District has temporary telecommute agreements in place and a technology infrastructure which has allowed a large number of nonoperational employees to work remotely. The District has health monitoring, testing access, and protective measures in place for employees working at District facilities and in the field. The District continues to monitor local, state, and federal confirmed cases of COVID-19, state and local government orders and guidance and related factors to adjust to changing conditions as warranted.

On March 20, 2020, the District temporarily suspended disconnections for non-payment of service and waived assessment of late payment charges effective April 12, 2020. In addition, the District's customer service centers suspended walk-in customer traffic on March 18, 2020. In August 2020, late payment charge assessments and disconnections for non-payment actions resumed for any charges billed and not paid by the due date. Temporary accommodations were made to address specific customer financial situations. The District continues to encourage customers experiencing financial hardship to seek assistance to pay their bills through various public and private resources. Average past due amounts at the end of 2020 were comparable to previous averages. The overall economic impact on the District from COVID-19 has been relatively small.

Vaccines are being administered in Nebraska and throughout the world. On February 2, 2021, most statewide restrictions were lifted in Nebraska due to a decrease in COVID-19 activity and related hospitalizations. Nebraska has moved from the blue to the green phase of its reopening plan. Other states have also lifted and relaxed restrictions.

As a result of the COVID-19 pandemic and the associated economic impact, the District has experienced a small reduction in overall customer electric consumption. The District's 2020 firm revenues were approximately two percent below the District's revenue budget entering 2020. The District has lowered its forecasted firm revenues by two percent for 2021. The District did not need to increase 2021 rates.

The District cannot predict the ultimate duration or extent of the COVID-19 pandemic, to what extent the pandemic may affect the operations and revenues of the District, to what extent COVID-19 may disrupt the local, state, national and global economy, or whether such disruption may adversely affect the future finances and operations of the District; or to what extent the District may provide additional waivers, other changes to its customers or billing and collections practices, or whether any of the foregoing may have a material adverse effect on the finances and operations of the District.

MARCH 2019 WEATHER EVENTS AND SPENCER HYDRO FACILITY

In mid-March 2019, multiple river basins in northern and eastern Nebraska, as well as river basins in the surrounding region, experienced unprecedented weather conditions as a result of exiting snowpack, blizzard conditions, frozen ground, significant rainfall and ice conditions on and around numerous rivers and their tributaries. The District sustained significant damage at the Spencer Hydro Facility, a small hydro plant on the Niobrara River in northern Nebraska accredited at 1.28 MW, which produced 10,509 megawatt hours ("MWh") in 2018. The Spencer Hydro Facility, including the hydro plant and the concrete and earthen dam structures (collectively, the "Spencer Hydro Facility") was damaged due to an inflow of ice and water. An individual living below the dam has been missing and declared dead. The District also experienced damages to transmission and substation facilities. Certain distribution facilities were also damaged, and a small number of customers lost service for an extended period due to protracted flood conditions in low-lying areas. CNS declared a Notice of Unusual Event for several days due to flooding conditions along the Missouri River, but operated continuously during the period. Restoration costs for all facilities, except the Spencer Hydro Facility, through December 31, 2020 were $10.1 million. The estimated cost to decommission the Spencer Hydro Facility is $9.4 million. As of December 31, 2020, $1.3 million had been incurred for preliminary damage assessments by District employees and external consultants, and for site safety and security of the Spencer Hydro Facility.

The District has been working with the Federal Emergency Management Agency ("FEMA") to make appropriate claims for reimbursement for a portion of the storm-related costs. The District estimates that approximately 60-70% of the costs from the March 2019 weather events may be reimbursed by FEMA. FEMA is requiring a detailed study on the cost of rebuilding and the cost of removing the Spencer Hydro Facility, which the District is pursuing through an engineering firm. The District expects to eventually remove the Spencer Hydro Facility which will require approval from the Nebraska Department of Natural Resources (the "NDNR"), which regulates the Spencer Hydro Facility, with input from other state and federal agencies.

The NDNR requested an independent investigation of the events at the Spencer Hydro Facility through the Association of State Dam Safety Officials (the "ASDSO"). The ASDSO issued its report in April 2020 and found that the flood of water and ice greatly exceeded the capacity of the dam and its spillways and that there was nothing the dam operators could have done to prevent the dam from failing. However, the ASDSO identified two key human factors contributing to the dam failures and consequences. The first factor was the lack of industry knowledge about ice run dam storm damage, the NDNR did not know that the Spencer Hydro Facility had failed in 1960 and 1966, and the District had limited knowledge of such prior failures. The second factor was that the NDNR and the District, based on the dam's hazard classification, underestimated the potential of the dam to cause life-threatening flooding in the event of a dam failure. The District is continuing to study the report and dispute certain findings in the report.

Information on litigation related to these weather events is included in Note 13 in the Notes to Financial Statements.

RESOURCE PLANNING

The District uses a diverse mix of generation resources such as coal, nuclear, natural gas, hydro, wind and solar to meet its firm requirement customer's needs. In 2020, a refueling year for the District's nuclear facility, the non-carbon energy resources as a percentage of native load sales were 62%. In 2019, the non-carbon energy resources as a percentage of native load sales were 68%.

The District's Board of Directors approved the Integrated Resource Plan ("IRP") during the first quarter of 2018. The District communicated the IRP, its development, rationale, and results through a variety of methods including several Board meetings, wholesale customer meetings, and communications to the public. The IRP is for a five-year time period. The reasons for a five-year time period include: the planning horizon for new supply side resources is relatively short for non-nuclear and non-coal resources; the nature of the utility business is evolving and a longer view is not as applicable as in the in past; the environmental regulatory landscape uncertainty; the continued addition of renewable resources in the SPP footprint resulting in surplus capacity; and the 2016 Contracts allow for a ten percent renewable self-supply option. The IRP determined the District's existing resources are adequate to meet the needs of the wholesale and retail customers within this time period. The retail division of the District is also considering the addition of some smaller renewable resources as allowed by the 2016 Contracts. The District will begin the preparation of an updated comprehensive IRP, with an expected completion date of 2023.

At the time of the 2018 IRP, the District was expecting to enter into a contract with Monolith Materials, Inc. ("Monolith") to purchase their production of hydrogen rich gas which the District was then going to use to convert its existing coal-fired boiler at Sheldon Unit No. 2 to burn the hydrogen rich gas. Monolith has since announced they will use the hydrogen rich gas for their own purposes. Monolith began construction of a carbon black facility adjacent to the District's Sheldon Station coal-fired generating facility in Nebraska. The construction of the carbon black facility is expected to be accomplished in two phases. Groundbreaking for Phase 1 of the carbon black facility occurred in October 2016 and became fully operational in 2020. The District has been informed that the Phase 1 carbon black plant began to produce carbon black in September 2020. Phase 2 construction is planned to begin in the second half of 2022 with commercial operation scheduled for 2024.

The District and Monolith have executed a Letter of Intent (the "LOI") outlining the intent of the parties to supply energy from 100 percent renewable resources to fuel Monolith's carbon black facilities. The LOI is subject to termination by either party as provided in the LOI. Pursuant to the LOI, the District has agreed to solicit bids from renewable energy developers for up to two million MWh of renewable energy. The LOI contemplates that the District would enter into power purchase agreements with the renewable energy resource developers and for the District and Monolith to enter into agreements that would provide the methodology for reimbursement of the District's cost of supplying such energy. Any agreement with such developers and Monolith would be subject to Board approval. The LOI provides for the procurement process for the renewable energy resources to be completed during the third quarter of 2021.

The electric load to serve the Monolith facility will be served by Norris Public Power District, a firm wholesale customer of the District. At full buildout, Monolith could be the single-largest industrial customer served in the District's territory. In order to serve Monolith's carbon black facility, the District will need to invest in additional transmission facilities in order to serve the load. The District received a Notice to Construct from SPP related to these transmission facilities with an estimated cost of $52.1 million and expects to spend an estimated $25.6 million in additional transmission substation costs. The District expects to recover approximately 63 percent of the Notice to Construct costs from other SPP members.

The District has entered into an agreement with Monolith to construct certain transmission and other electric facilities necessary to provide energy to Monolith's carbon black production facility. The estimated cost of construction of such facilities is approximately $27.1 million which Monolith has agreed to pay during the construction period if the carbon black facility is not completed and for a certain period after completion. The District has secured Monolith's payment obligations by certain credit support measures provided in the agreement, which include, one or more letters of credit or cash held in escrow or a combination thereof.

ENERGY RISK MANAGEMENT PRACTICES

The nature of the District's business exposes it to a variety of risks, including exposure to volatility in electric energy and fuel prices, uncertainty in load and resource availability, the creditworthiness of its counterparties, and the operational risks associated with transacting in the wholesale energy markets.

To help manage energy risks, including the risks related to the District's participation in the SPP Integrated Market, the District relies upon TEA to both transact on its behalf in the wholesale energy markets and to develop and recommend strategies to manage the District's exposure to risks in the wholesale energy markets. TEA combines a strong knowledge of the District's system, an in-depth understanding of the wholesale energy markets, experienced people, and state-of-the-art technology to deliver a broad range of standardized and customized energy products and services to the District.

TEA has assisted the District in developing its Energy Risk Management ("ERM") program. The program originates with the Board-approved ERM Governing Policy and the ERM-Approved Products and Limits Standard. These documents establish the philosophy, objectives, delegation of authorities, approved products and their limits on the District's energy and fuel activities necessary to govern its ERM program. The objective of the ERM program is to increase fuel and energy price stability by hedging the risk of significant adverse impacts to cash flow. These adverse impacts could be caused by events such as natural gas or power price volatility or extended unplanned outages. The ERM program has been developed to provide assurance to the Board that the risks inherent in the wholesale energy market are being quantified and appropriately managed.

ECONOMIC FACTORS

Preliminary data indicate that following ten consecutive years of growth, Nebraska's inflation adjusted, estimated gross state product decreased by 0.9% from the third quarter of 2019 to the third quarter of 2020. The U.S. economy experienced a 2.3% decrease in real national gross domestic product over the same, 12-month period. Increases in Nebraska's "Agriculture, Forestry, Fishing, and Hunting" (+12.5%) and "Finance and Insurance" (+9.6%) industries were more than offset by declines in "Accommodation and Food Services" (-14.4%), "Transportation and Warehousing" (-13.6%), "Health Care and Social Assistance" (-3.8%), and "State and Local Government" (-3.5%). The COVID-19 pandemic was the major factor in the slowdown of both the U.S. and Nebraska economies in 2020.

Nebraska and the Midwest region continue to experience unemployment rates that are below the national average. Nebraska's revised average annual unemployment rate increased from the revised 2019 value of 3.0% to 4.2% in 2020. This was well below the 2020 national average unemployment rate of 8.1%. Nebraska's revised, seasonally adjusted unemployment rate was 3.4% in December 2020, up from the revised 2.9% in December 2019. Both numbers were well below the national December seasonally adjusted unemployment rates of 6.7% in 2020 and 3.6% in 2019. Nebraska's revised December 2020 unemployment rate was the third lowest in the nation. The District continues to monitor changes in national and global economic conditions, as these could impact the cost of debt and access to capital markets.

CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY AND THE NATION

The Electric Utility Industry in General

The electric utility industry has been, and in the future may be, affected by a number of factors which could impact the financial condition and competitiveness of electric utilities, such as the District. Such factors include, among others:

- effects of compliance with changing environmental, safety, licensing, regulatory, and legislative requirements,
- changes resulting from energy efficiency and demand-side management programs on the timing and use of electric energy,
- other federal and state legislative and regulatory changes,
- increased wholesale competition from independent power producers, marketers, and brokers,
- “self-generation” by certain industrial and commercial customers,
- issues relating to the ability to issue tax-exempt obligations,
- severe restrictions on the ability to sell to nongovernmental entities electricity from generation projects financed with outstanding tax-exempt obligations,
- changes from projected future load requirements,
- increases in costs,
- shifts in the availability and relative costs of different fuels,
- inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy, fuel, and transmission capacity,
- effects of financial instability of various participants in the power market,
- climate change and the potential contributions made to climate change by coal-fired and other fossil-fueled generating units,
- challenges associated with additional renewable generation, and
- issues relating to cyber and physical security.

Any of these general factors (as well as other factors) could have an effect on the financial condition of the District.

Competitive Environment in Nebraska

While wholesale competition is expected to increase in the future, there is a Nebraska statute that prohibits competition for retail customers. Pursuant to state statutes, retail suppliers of electricity have exclusive rights to serve customers at retail in their respective service territories. Any transfer of retail customers or service territories between retail electric suppliers may be done only upon agreement of the respective retail electric suppliers and/or pursuant to an order of the Nebraska Power Review Board. While state statutes do not provide for wholesale suppliers of electricity to have exclusive rights to serve a particular area or customer at wholesale, wholesale power suppliers are permitted to voluntarily enter into agreements with other wholesale power suppliers limiting the areas or customers to whom they may sell energy at wholesale. The District has entered into several such agreements.

Report of Independent Auditors

To the Board of Directors of the Nebraska Public Power District

We have audited the accompanying financial statements of the Nebraska Public Power District (the "District"), which comprise the statements of net position – business-type activities and of fiduciary net position – postemployment medical and life benefits plan as of December 31, 2020 and 2019, and the related statements of revenues, expenses, and changes in net position – business-type activities, of changes in fiduciary net position – postemployment medical and life benefits plan, and of cash flows – business type activities for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the District's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the District's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Opinions

In our opinion, the financial statements referred to above present fairly, in all material respects, the respective financial position of the business-type activities and the fiduciary activities of the Nebraska Public Power District as of December 31, 2020 and 2019, and the respective changes in financial position and, where applicable, cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matters

Required supplemental information

The accompanying management's discussion and analysis on pages 6 through 23 and the supplemental schedules on pages 62 through 66 are required by accounting principles generally accepted in the United States of America to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audits of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other information

Our audits were conducted for the purpose of forming opinions on the financial statements that collectively comprise the District's basic financial statements. The statistical review on page 5 is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has not been subjected to the auditing procedures applied in the audits of the basic financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

PricewaterhouseCoopers LLP

Chicago, Illinois
April 7, 2021

Statements of Net Position - Business-Type Activities
Nebraska Public Power District

As of December 31, (in 000's)	2020	2019
ASSETS AND DEFERRED OUTFLOWS		
Current Assets:		
Cash and cash equivalents	$ 23,767	$ 16,245
Investments	590,811	706,346
Receivables, less allowance for doubtful accounts of $510 and $505, respectively	111,139	116,404
Fossil fuels, at average cost	27,628	23,758
Materials and supplies, at average cost	115,256	112,236
Prepayments and other current assets	15,503	16,000
	884,104	990,989
Special Purpose Funds:		
Construction funds	32,777	32,417
Debt service and reserve funds	81,632	82,189
Employee benefit funds	3,963	3,249
Decommissioning funds	706,200	652,737
	824,572	770,592
Utility Plant, at Cost:		
Utility plant in service	5,152,673	5,092,041
Less reserve for depreciation	2,951,378	2,852,286
	2,201,295	2,239,755
Construction work in progress	230,751	154,264
Nuclear fuel, at amortized cost	139,335	138,787
	2,571,381	2,532,806
Other Long-Term Assets:		
Regulatory asset for other postemployment benefits	120,944	152,386
Long-term capacity contracts	131,967	138,979
Unamortized financing costs	6,808	7,120
Investment in The Energy Authority	9,420	7,581
Other	6,378	6,097
	275,517	312,163
Total Assets	4,555,574	4,606,550
Deferred Outflows of Resources:		
Asset retirement obligation	35,100	205,461
Unamortized cost of refunded debt	26,227	29,937
Other postemployment benefits	40,424	58,770
	101,751	294,168
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 4,657,325	$ 4,900,718
LIABILITIES, DEFERRED INFLOWS, AND NET POSITION		
Current Liabilities:		
Revenue bonds, current	$ 79,140	$ 81,455
Revolving credit agreements and notes, current	113,999	80,836
Accounts payable and accrued liabilities	72,327	90,856
Accrued in lieu of tax payments	9,750	10,197
Accrued payments to retail communities	2,121	2,131
Accrued compensated absences	20,726	18,257
Other	11,308	10,130
	309,371	293,862
Long-Term Debt:		
Revenue bonds, net of current	1,323,489	1,336,092
Revolving credit agreements and notes, net of current	21,919	146,317
	1,345,408	1,482,409
Other Long-Term Liabilities:		
Asset retirement obligation	743,860	859,393
Net other postemployment benefit liability	22,940	105,234
Other	25,388	16,447
	792,188	981,074
Total Liabilities	2,446,967	2,757,345
Deferred Inflows of Resources:		
Unearned revenues	201,589	262,500
Other deferred inflows	254,552	222,548
	456,141	485,048
Net Position:		
Net investment in capital assets	1,245,645	1,194,547
Restricted	30,044	30,191
Unrestricted	478,528	433,587
	1,754,217	1,658,325
TOTAL LIABILITIES, DEFERRED INFLOWS, AND NET POSITION	$ 4,657,325	$ 4,900,718

The accompanying notes to financial statements are an integral part of these statements.

Statements of Revenues, Expenses, and Changes in Net Position - Business-Type Activities
Nebraska Public Power District

For the years ended December 31, (in 000's)	2020	2019
Operating Revenues	$ 1,103,149	$ 1,074,475
Operating Expenses:		
Power purchased	168,232	154,931
Production:		
Fuel	141,578	166,661
Operation and maintenance	271,603	238,533
Transmission and distribution operation and maintenance	106,668	104,359
Customer service and information	16,115	15,877
Administrative and general	90,691	101,995
Payments to retail communities	28,252	27,983
Decommissioning	52,688	28,544
Depreciation and amortization	126,215	124,972
Payments in lieu of taxes	9,795	10,247
	1,011,837	974,102
Operating Income	91,312	100,373
Investment and Other Income:		
Investment income	49,307	44,692
Other income	2,322	2,358
	51,629	47,050
Increase in Net Position Before Debt and Other Expenses	142,941	147,423
Debt and Related Expenses:		
Interest on revenue bonds	59,787	65,657
Allowance for funds used during construction	(3,466)	(2,481)
Bond premium amortization net of debt issuance expense	(11,695)	(11,274)
Interest on revolving credit agreements and notes	2,423	6,337
	47,049	58,239
Increase in Net Position	95,892	89,184
Net Position:		
Beginning balance	1,658,325	1,569,141
Ending balance	$ 1,754,217	$ 1,658,325

The accompanying notes to financial statements are an integral part of these statements.

Statements of Cash Flows - Business-Type Activities
Nebraska Public Power District

For the years ended December 31, (in 000's)	2020	2019
Cash Flows from Operating Activities:		
Receipts from customers and others	$ 991,172	$ 1,077,598
Other receipts	339	9,338
Payments to suppliers and vendors	(523,968)	(481,230)
Payments to employees	(262,112)	(247,681)
Net cash provided by operating activities	205,431	358,025
Cash Flows from Investing Activities:		
Proceeds from sales and maturities of investments	3,775,452	3,110,453
Purchases of investments	(3,698,352)	(3,202,609)
Income received on investments	51,142	33,794
Net cash provided by (used in) investing activities	128,242	(58,362)
Cash Flows from Capital and Related Financing Activities:		
Proceeds from issuance of revenue bonds	125,825	132,195
Proceeds from revolving credit agreements and notes	76,105	28,298
Capital expenditures for utility plant	(202,772)	(130,127)
Contributions in aid of construction and other reimbursements	27,594	14,522
Principal payments on revenue bonds	(124,250)	(221,990)
Interest payments on revenue bonds	(60,940)	(66,272)
Interest paid on defeased revenue bonds	-	(6,875)
Principal payments on revolving credit agreements and notes	(167,340)	(56,109)
Interest payments on revolving credit agreements and notes	(2,709)	(6,474)
Other non-operating revenues	2,336	3,912
Net cash used in capital and related financing activities	(326,151)	(308,920)
Net increase (decrease) in cash and cash equivalents	7,522	(9,257)
Cash and cash equivalents, beginning of year	16,245	25,502
Cash and cash equivalents, end of year	$ 23,767	$ 16,245
Reconciliation of Operating Income to Cash Provided By Operating Activities:		
Operating income	$ 91,312	$ 100,373
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation and amortization	126,215	124,972
Undistributed net revenue - The Energy Authority	210	26
Decommissioning, net of customer contributions	38,757	22,606
Amortization of nuclear fuel	35,025	40,115
Changes in assets and liabilities which provided (used) cash:		
Receivables, net	3,834	19,417
Fossil fuels	(3,870)	(4,213)
Materials and supplies	(3,020)	1,061
Prepayments and other current assets	558	(505)
Other long-term assets	(501)	1,046
Accounts payable and accrued payments to retail communities	(17,309)	12,928
Unearned revenues	(60,911)	14,647
Other deferred inflows	(5,494)	26,005
Other liabilities	625	(453)
Net cash provided by operating activities	$ 205,431	$ 358,025
Supplementary Non-Cash Capital Activities:		
Change in utility plant additions in accounts payable	$ (1,138)	$ 16,220

The accompanying notes to financial statements are an integral part of these statements.

Statements of Fiduciary Net Position - Postemployment Medical and Life Benefits Plan
Nebraska Public Power District

As of December 31, (in 000's)	2020	2019
Assets:		
Cash and cash equivalents	$ 7,134	$ 2,061
Receivables:		
Contributions	-	12,800
Investment income	487	493
Investments	336,331	267,443
Total Assets	343,952	282,797
Liabilities:		
Payables:		
Benefits - healthcare	216	400
Benefits - life insurance	38	16
Investment expense	116	92
Professional, administrative and other expenses	32	29
Total liabilities	402	537
Net Position - Restricted for Other Postemployment Benefits	$ 343,550	$ 282,260

The accompanying notes to financial statements are an integral part of these statements.

Statements of Changes in Fiduciary Net Position - Postemployment Medical and Life Benefits Plan
Nebraska Public Power District

For the Years Ended December 31, (in 000's)	2020	2019
Additions:		
Contributions		
Employer	$ 28,283	$ 41,084
Investment Income:		
Net appreciation in fair value of investments	43,642	38,025
Interest and dividends	4,229	4,380
Total investment income	47,871	42,405
Less: Investment expenses	(634)	(672)
Net investment income	47,237	41,733
Total additions	75,520	82,817
Deductions:		
Health care benefits	13,807	12,606
Life insurance benefits	218	201
Professional, administrative and other expenses	205	188
Total deductions	14,230	12,995
Increase in Net Position	61,290	69,822
Net Position - Restricted for Other Postemployment Benefits		
Beginning balance	282,260	212,438
Ending balance	$ 343,550	$ 282,260

The accompanying notes to financial statements are an integral part of these statements.

NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

A. *Organization* –
Nebraska Public Power District ("District"), a public corporation and a political subdivision of the State of Nebraska, operates an integrated electric utility system which includes facilities for the generation, transmission, and distribution of electric power and energy to its Retail and Wholesale customers. The control of the District and its operations is vested in a Board of Directors ("Board") consisting of 11 members popularly elected from districts comprising subdivisions of the District's chartered territory. The Board is authorized to establish rates.

B. *Basis of Accounting* –
The financial statements are prepared in accordance with Generally Accepted Accounting Principles ("GAAP") for accounting guidance provided by the Governmental Accounting Standards Board ("GASB") for proprietary funds of governmental entities. In the absence of established GASB pronouncements, other accounting literature is considered including guidance provided in the Financial Accounting Standards Board ("FASB") Accounting Standards Codification.

The District applies the accounting policies established in the GASB codification Section Re10, *Regulated Operations.* This guidance permits an entity with cost-based rates and Board authorization to include revenues or costs in a period other than the period in which the revenues or costs would be reported by an unregulated entity.

C. *Revenue* –
Retail and wholesale revenues are recorded in the period in which services are rendered. Revenues and expenses related to providing energy services in connection with the District's principal ongoing operations are classified as operating. All other revenues and expenses are classified as non-operating and reported as investment and other income or debt and related expenses on the Statements of Revenues, Expenses and Changes in Net Position.

D. *Cash and Cash Equivalents* –
The operating fund accounts are called Revenue Funds. There is a separate investment account for the Revenue Funds. The District reports highly liquid investments in the Revenue Funds with an original maturity of three months or less to be cash and cash equivalents on the balance sheet, except for these types of investments in the Revenue Funds investment account. Cash and cash equivalents in the investment accounts for the Revenue Funds and the Special Purpose Funds are reported as investments on the balance sheet.

E. *Fossil Fuel and Materials and Supplies* –
The District maintains inventories for fossil fuels and materials and supplies which are valued at average cost. Obsolete inventory is expensed and removed from inventory.

F. *Utility Plant, Depreciation, Amortization, and Maintenance* –
Utility plant is stated at cost, which includes property additions, replacements of units of property and betterments. The District charges maintenance and repairs, including the cost of renewals and replacements of minor items of property, to maintenance expense accounts when incurred. Upon retirement of property subject to depreciation, the cost of property is removed from the utility plant accounts and charged to the reserve for depreciation, net of salvage.

The District records depreciation over the estimated useful life of the property primarily on a straight-line basis. Depreciation on utility plant was approximately 2.3% for the years ended December 31, 2020 and 2019. The District had fully depreciated utility plant, primarily related to Cooper Nuclear Station ("CNS"), which was still in service of $1,344.8 million and $1,321.4 million as of December 31, 2020 and 2019, respectively.

The District has long-term Professional Retail Operations ("PRO") Agreements with 79 municipalities for certain retail electric distribution systems. These PRO Agreements obligate the District to make payments based on gross revenues from the municipalities and pay for normal property additions during the term of the agreements. The District recorded amortization for these utility plant additions of $12.7 million and $10.8 million in 2020 and 2019, respectively, which was included in depreciation and amortization expense. These utility plant additions, which were fully amortized, totaled $220.0 million and $208.9 million as of December 31, 2020 and 2019, respectively.

G. *Allowance for Funds Used During Construction ("AFUDC")* –
This allowance, which represents the cost of funds used to finance construction, is capitalized as a component of the cost of the utility plant. The capitalization rate depends on the source of financing. The rate for construction financed with revenue bonds is based upon the interest cost of each bond issue less interest income. Construction financed on a short-term basis with tax-exempt revolving credit agreement ("TERCA") or taxable revolving credit agreement ("TRCA") is charged a rate based upon the projected average interest cost of the related debt outstanding. For the periods presented herein, the AFUDC rates for construction funded by revenue bonds varied from 0.6% to 4.0%. For construction financed on a short-term basis, the rate was 2.5% for 2020 and 3.0% for 2019.

H. *Nuclear Fuel* –
Nuclear fuel inventories are included in utility plant. The nuclear fuel cycle requirements are satisfied through the procurement of raw material in the form of natural uranium, conversion services of such material to uranium hexafluoride, uranium hexafluoride that has already been converted from uranium, enrichment services, and fuel fabrication and related services. The District purchases uranium and uranium hexafluoride on the spot market and carries inventory in advance of the refueling requirements and schedule. Nuclear fuel in the reactor is being amortized on the basis of energy produced as a percentage of total energy expected to be produced. Fees for disposal of fuel in the reactor are being expensed as part of the fuel cost.

I. *Unamortized Financing Costs* –
These costs include issuance expenses for bonds which are being amortized over the life of the respective bonds using the bonds outstanding method. Deferred unamortized financing costs associated with bonds refunded are amortized using the bonds outstanding method over the shorter of the original or refunded life of the respective bonds. Regulatory accounting, GASB codification section Re10, *Regulated Operations,* is used to amortize these costs over their respective periods.

J. *Asset Retirement Obligations* –
Asset retirement obligations ("ARO") represent the best estimate of the current value of cash outlays expected to be incurred for legally enforceable retirement obligations of tangible capital assets. Regulatory accounting, GASB codification section Re10, *Regulated Operations,* is used to recognize these costs consistent with the rate treatment.

K. *Other Postemployment Benefits ("OPEB")* –
For purposes of measuring the net OPEB liability, deferred outflows of resources and deferred inflows of resources related to OPEB, and OPEB expense, information about the fiduciary net position of the District's Postemployment Medical and Life Benefits Plan ("Plan") and additions to/deductions from the Plan's fiduciary net position have been determined on the same basis as they are reported by the Plan. For this purpose, the Plan recognizes benefit payments when due and payable in accordance with the benefit terms. Investments are reported at fair value, except for certain investments in a real estate fund, an international equity fund, and a U.S. equity fund, which are reported at net asset value.

L. *Auction Revenue Rights and Transmission Congestion Rights* –
The District uses Auction Revenue Rights ("ARR") and Transmission Congestion Rights ("TCR") in the Southwest Power Pool ("SPP") Integrated Market to hedge against transmission congestion charges. These financial instruments were primarily designed to allow firm transmission customers the opportunity to offset price differences due to transmission congestion costs between resources and loads. Awarded ARR provide a fixed revenue stream to offset congestion costs. TCR can be acquired through the conversion of ARR or purchases from SPP auctions or secondary market trades. The financial transactions for all ARR/TCR activity in SPP are netted and recorded as other sales, as the District is generally a net seller in SPP. Unearned revenues are recorded for awarded ARR, net of conversion of TCR, until the revenues are realized in the SPP Integrated Market financial transactions. Outstanding TCR positions are recorded on the balance sheet until expired.

M. *Deferred Outflows of Resources and Deferred Inflows of Resources* –
Deferred outflows of resources are consumptions of assets that are applicable to future reporting. Regulatory accounting is used for ARO. The ARO deferred outflow is the difference between the related liability amount and rate collections and the interest earned on decommissioning funds. The cost of refunded debt is the difference in the reacquisition price and the net carrying amount of the refunded debt in an advance refunding. Deferred outflows related to OPEB include unrealized contributions and losses.

Deferred inflows of resources are acquired assets that are applicable to future reporting periods and consist of regulatory liabilities for unearned revenues and other deferred inflows. Other deferred inflows include Department of Energy ("DOE") settlements, nuclear fuel disposal collections, CNS outage collections, unrealized OPEB gains, settlements for termination of certain power and transmission agreements, non-nuclear decommissioning collections and a sales tax refund from the State of Nebraska for the construction of a renewable energy facility.

The District is required under the General Revenue Bond Resolution ("General Resolution") to charge rates for electric power and energy so that revenues will be at least sufficient to pay operating expenses, aggregate debt service on the General Revenue Bonds, amounts to be paid into the Debt reserve fund and all other charges or liens payable out of revenues. In the event the District's rates for wholesale service result in a surplus or deficit in revenues during a rate period, such surplus or deficit, within certain limits, may be retained in a rate stabilization account. Any amounts in excess of the limits will be considered in projecting revenue requirements and establishing rates in future rate periods. Such treatment of wholesale revenues is stipulated by the District's long-term wholesale power supply contracts. The District accounts for any surplus or deficit in revenues for retail service in a similar manner.

The following table summarizes the balance of Unearned revenues as of December 31, 2020 and 2019 and activity for the years then ended (in 000's):

	2020	2019
Unearned revenues, beginning of year	$ 262,500	$ 247,853
Surpluses	14,883	71,292
Use of prior period rate stabilization funds in rates	(75,794)	(56,645)
Unearned revenues, end of year	$ 201,589	$ 262,500

The DOE settlements regulatory liability was established for the reimbursement from the DOE for costs incurred by the District in conjunction with the disposal of spent nuclear fuel from CNS. Details of the District's DOE settlements are included in Note 12 in the Notes to Financial Statements.

The District includes in rates the costs associated with nuclear fuel disposal. Such collections were remitted to the DOE under the Nuclear Waste Policy Act until the DOE adjusted the spent fuel disposal fee to zero, effective May 16, 2014. The Board authorized the use of regulatory accounting for the continued collection of these costs. This approach ensures costs are recognized in the appropriate period with customers receiving the benefits from CNS paying the appropriate costs. The expense for spent nuclear fuel disposal is recorded at the previous DOE rate based on net electricity generated and sold and the regulatory liability will be eliminated when payments are made for spent nuclear fuel disposal. Additional details of the District's DOE spent nuclear fuel collections are included in Note 12 in the Notes to Financial Statements.

In 2019, the District collected revenues for the costs of the 2020 CNS refueling and maintenance outage. This regulatory liability was included in Other deferred inflows on the Balance Sheets and was amortized through revenue during 2020, the year of the outage.

The District and Heartland Consumers Power District ("Heartland") executed a termination and release agreement in 2018 for certain transmission services. The District and the City of Lincoln, Nebraska ("Lincoln") executed a termination and release agreement in 2017 for the Sheldon Station ("Sheldon") Participation Agreement. The Board authorized the use of regulatory accounting for these settlement payments. These regulatory liabilities were included in Other deferred inflows on the Balance Sheets and will be eliminated as the revenues from the settlement payments are incorporated in future rates.

The District collects in rates for non-nuclear decommissioning costs. The collections for assets which do not have a legally required retirement obligation are recorded as a regulatory liability and are included, along with the interest on these funds, in Other deferred inflows on the Balance Sheets.

The following table summarizes the balance of Other deferred inflows of resources as of December 31, 2020 and 2019 (in 000's):

	2020	2019
DOE settlements	$ 78,311	$ 72,046
Nuclear fuel disposal collections	39,013	33,261
CNS outage collections	-	21,000
Settlements for termination of agreements	34,660	38,864
Unrealized OPEB gains	69,274	36,768
Non-nuclear decommissioning collections	29,641	16,672
Renewable energy facility sales tax refund	3,653	3,937
	$ 254,552	$ 222,548

N. *Net Position –*
Net position is made up of three components: Net investment in capital assets, Restricted, and Unrestricted.

Net investment in capital assets consisted of utility plant assets, net of accumulated depreciation and reduced by the outstanding balances of any bonds or notes that are attributable to the acquisition, construction, or improvement of these assets. This component also included long-term capacity contracts, net of the outstanding balances of any bonds or notes attributable to these assets.

Restricted net position consisted of the Primary account in the Debt reserve funds that are required deposits under the General Resolution and the Decommissioning funds, net of any related liabilities.

Unrestricted net position consisted of any remaining net position that does not meet the definition of Net investment in capital assets or Restricted and is used to provide for working capital to fund fuel and inventory requirements, as well as other operating needs of the District.

O. *Use of Estimates –*
The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

P. *Recent Accounting Pronouncements –*
GASB Statement No. 87, *Leases,* was issued in June 2017. This Statement will bring substantially all leases for lessees on to the balance sheet. For operating leases, lessees will be required to recognize an asset for the right to use the leased item and a corresponding lease liability. Lease liabilities will be considered long-term debt and lease payments will be capital financing outflows in the cash flow statement. In the activity statement, lessees will no longer report rent expense for operating-type leases; but, will instead report interest expense on the liability and amortization expense related to the asset. For lessors, the accounting will mirror lessee accounting. Lessors will recognize a lease receivable and a corresponding deferred inflow of resources (with certain exceptions), while continuing to report the asset underlying the lease. Interest income associated with the receivable will be recognized using the effective interest method. Lease revenue will arise from amortizing the deferred inflow of resources in a systematic and rational manner over the lease term. In March 2020, the Board authorized the use of regulatory accounting to continue the revenue and expense recognition for leases consistent with the rate methodology as used for the District's customers. In May 2020, GASB issued Statement No. 95, *Postponement of the Effective Dates of Certain Authoritative Guidance*, which delayed the effective date of GASB Statement No. 87 by 18 months due to the COVID-19 pandemic. The requirements of this Statement will be implemented, using regulatory accounting, in 2022.

GASB Statement No. 89, *Accounting for Interest Cost Incurred Before the End of a Construction Period,* was issued in June 2018. This Statement requires that interest cost incurred before the end of a construction period be recognized as an expense in the period in which the cost is incurred instead of as an addition to the cost of the utility plant asset. In March 2020, the Board authorized the use of regulatory accounting to continue to capitalize interest during construction to ensure the transmission rates the District charges regional transmission organization customers are consistent with the interest capitalization methodology used by investor-owned utilities and to avoid a shifting of costs to other District customers. In May 2020, GASB issued Statement No. 95, *Postponement of the Effective Dates of Certain Authoritative Guidance*, which delayed the effective date of GASB Statement No. 89 by one year due to the COVID-19 pandemic. The requirements of Statement No. 89 will be implemented, using regulatory accounting, in 2021.

GASB Statement No. 93, *Replacement of Interbank Offered Rates*, was issued in March 2020. As a result of global reference rate reform, the London Interbank Offered Rate ("LIBOR") is expected to cease to exist in its current form. This Statement addresses the accounting and financial reporting effects that result from the replacement of interbank offered rates with other references rates. The removal of LIBOR as an appropriate benchmark interest rate is effective for reporting periods ending after December 31, 2021. All other requirements of this Statement are effective for reporting periods beginning after June 15, 2020. The District will implement the removal of LIBOR as a benchmark requirement of Statement No. 93 in 2022 as it relates to TERCA and TRCA. Management will continue to evaluate other reference rates and the impact of this statement.

GASB Statement No. 94, *Public-Private and Public-Public Partnerships and Availability Payment Arrangements*, was issued in March 2020. This Statement is intended to improve comparability of financial statements among governments that enter into public-private and public-public partnerships and availability payment arrangements. The requirements of this Statement are effective for fiscal years beginning after June 15, 2022. Management is currently evaluating the impact of this statement.

GASB Statement No. 96, *Subscription-Based Information Technology Arrangements*, was issued in May 2020. This Statement establishes accounting and financial reporting requirements for subscription-based information technology arrangements ("SBITA") as no such guidance previously existed. SBITAs are arrangements in which the District has access to vendors' information technology ("IT") software and associated tangible capital assets for subscription payments but does not have a perpetual license or title to the IT software and associated tangible assets. The requirements of this Statement are effective for fiscal years beginning after June 15, 2022. Management is currently evaluating the impact of this statement.

2. CASH AND INVESTMENTS:

Investments are recorded at fair value with the changes in the fair value of investments reported as Investment income in the accompanying Statements of Revenues, Expenses, and Changes in Net Position. The District had unrealized net gains of $0.5 million and $4.0 million in 2020 and 2019, respectively.

The fair value of all cash and investments, regardless of classification on the Balance Sheets, was as follows as of December 31 (in 000's):

	2020		2019	
	Fair Value	Weighted Average Maturity (Years)	Fair Value	Weighted Average Maturity (Years)
U.S. Treasury and government agency securities	$ 972,798	2.8	$ 1,121,219	3.1
Corporate bonds	223,507	15.4	201,524	13.4
Municipal bonds	22,094	13.7	10,234	12.7
Cash and cash equivalents	220,751	0.2	160,206	0.2
Total cash and investments	$ 1,439,150		$ 1,493,183	
Portfolio weighted average maturity		4.5		4.3

Interest Rate Risk – The investment strategy for all investments, except for the decommissioning funds, is to buy and hold securities until maturity, which minimizes interest rate risk. The investment strategy for decommissioning funds is to actively manage the diversification of multiple asset classes to achieve a rate of return equal to or exceeding the rate used in the decommissioning funding plan model assumptions. Accordingly, securities are bought and sold prior to maturity to increase opportunities for higher investment returns.

Credit Risk – The District follows a Board-approved Investment Policy. This policy complies with state and federal laws, and the General Resolution's provisions governing the investment of all funds. The majority of investments are direct obligations of, or obligations guaranteed by, the United States of America. Other investments are limited to investment-grade fixed income obligations.

Custodial Credit Risk – Cash deposits, primarily interest bearing, are covered by federal depository insurance, pledged collateral consisting of U.S. Government Securities held by various depositories, or an irrevocable, nontransferable, unconditional letter of credit issued by a Federal Home Loan Bank.

The fair values of the District’s Revenue and Special Purpose Funds as of December 31 were as follows (in 000’s):

The Revenue funds are used for operating activities for the District. Cash and cash equivalents in the Revenue funds are reported as such on the balance sheet, except cash and cash equivalents in the Revenue Fund investment account are reported as investments.

	2020	2019
Revenue funds - Cash and cash equivalents	$ 23,767	$ 16,245
Revenue funds - Cash equivalents in investments	168,045	124,768
Revenue funds - Investments	422,766	581,578
	$ 614,578	$ 722,591

The Construction funds are used for capital improvements, additions, and betterments to and extensions of the District’s system. The sources of monies for deposits to the construction funds are from revenue bond proceeds and the issuance of short-term debt.

	2020	2019
Construction funds - Cash and cash equivalents	$ -	$ 83
Construction funds - Investments	32,777	32,334
	$ 32,777	$ 32,417

The Debt service and reserve funds are established under the General Resolution. The Debt service funds are used for the payment of debt service. The Debt reserve funds consist of a Primary account and a Secondary account. The District is required by the General Resolution to maintain an amount equal to 50% of the maximum amount of interest accrued in the current or any future year in the Primary account. Such amount totaled $30.0 million and $30.2 million as of December 31, 2020 and 2019, respectively. The Secondary account can be established at such amounts and can be utilized for any lawful purpose as determined by the District’s Board. Such account totaled $51.6 million as of December 31, 2020 and 2019.

	2020	2019
Debt service and reserve funds - Investments	$ 81,632	$ 82,189

The Employee Benefit funds consist of a self-funded hospital-medical benefit plan for active employees only as of December 31, 2020 and 2019. The District pays 80% of the hospital-medical premiums with the employees paying the remaining 20% of the cost of such coverage.

	2020	2019
Employee benefit funds - Cash and cash equivalents	$ 3,963	$ 3,249

The Decommissioning funds are utilized to account for the investments held to fund the estimated cost of decommissioning CNS when its operating license expires. The Decommissioning funds are held by outside trustees or custodians in compliance with the decommissioning funding plans approved by the Board which are invested primarily in fixed income governmental securities.

	2020	2019
Decommissioning funds - Cash and cash equivalents	$ 24,976	$ 15,861
Decommissioning funds - Investments	681,224	636,876
	$ 706,200	$ 652,737

3. FAIR VALUE OF FINANCIAL INSTRUMENTS:

Fair value is the exchange price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants at the measurement date.

GASB Statement No. 72 ("GASB 72"), *Fair Value Measurement and Application*, establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in an active market for identical assets or liabilities and the lowest priority to unobservable inputs. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels of fair value hierarchy defined in GASB 72 are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The District's investments in cash and cash equivalents are included as Level 1 assets.

Level 2 – Pricing inputs are other than quoted market prices in the active markets included in Level 1, which are either directly or indirectly observable for the asset or liability as of the reporting date. Level 2 inputs include the following:

- quoted prices for similar assets or liabilities in active markets;
- quoted prices for identical assets or liabilities in inactive markets;
- inputs other than quoted prices that are observable for the asset or liability; or
- inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 2 assets primarily include U.S. Treasury and government agency securities held in the Revenue funds and other Special Purpose Funds and U.S. Treasury and government agency securities, corporate bonds, and municipal bonds held in the Decommissioning funds.

Level 3 – Pricing inputs include significant inputs that are unobservable and cannot be corroborated by market data. Level 3 assets and liabilities are valued based on internally developed models and assumptions or methodologies using significant unobservable inputs. The District currently does not have any Level 3 assets or liabilities.

The District performs an analysis annually to determine the appropriate hierarchy level classification of the assets and liabilities that are included within the scope of GASB 72. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. There were no liabilities within the scope of GASB 72 as of December 31, 2020 and 2019.

The following tables set forth the District's financial assets that are accounted for and reported at fair value on a recurring basis by level within the fair value hierarchy as of December 31, (in 000's):

	2020			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 537,175	$ -	$ 537,175
Cash and cash equivalents	195,775	-	-	195,775
Decommissioning funds:				
U.S. Treasury and government agency securities	-	435,623	-	435,623
Corporate bonds	-	223,507	-	223,507
Municipal bonds	-	22,094	-	22,094
Cash and cash equivalents	24,976	-	-	24,976
	$ 220,751	$1,218,399	$ -	$ 1,439,150

	2019			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 696,101	$ -	$ 696,101
Cash and cash equivalents	144,345	-	-	144,345
Decommissioning funds:				
U.S. Treasury and government agency securities	-	425,118	-	425,118
Corporate bonds	-	201,524	-	201,524
Municipal bonds	-	10,234	-	10,234
Cash and cash equivalents	15,861	-	-	15,861
	$ 160,206	$1,332,977	$ -	$ 1,493,183

4. UTILITY PLANT:

Utility plant activity for the year ended December 31, 2020, was as follows (in 000's):

	December 31, 2019	Increases	Decreases	December 31, 2020
Nondepreciable utility plant:				
Land and improvements	$ 78,494	$ 738	$ -	$ 79,232
Construction in progress	154,264	146,795	(70,308)	230,751
Total nondepreciable utility plant	232,758	147,533	(70,308)	309,983
Nuclear fuel*	138,787	35,573	(35,025)	139,335
Depreciable utility plant:				
Generation - Fossil	1,675,932	5,702	(3,428)	1,678,206
Generation - Nuclear	1,341,886	7,106	(1,924)	1,347,068
Transmission	1,377,517	30,374	(4,637)	1,403,254
Distribution	253,009	15,393	(5,406)	262,996
General	365,203	19,961	(3,247)	381,917
Total depreciable utility plant	5,013,547	78,536	(18,642)	5,073,441
Less reserve for depreciation	(2,852,286)	(117,734)	18,642	(2,951,378)
Depreciable utility plant, net	2,161,261	(39,198)	-	2,122,063
Utility plant activity, net	$ 2,532,806	$ 143,908	$ (105,333)	$ 2,571,381

* Nuclear fuel decreases represented amortization of $35.0 million.

Utility plant activity for the year ended December 31, 2019, was as follows (in 000's):

	December 31, 2018	Increases	Decreases	December 31, 2019
Nondepreciable utility plant:				
Land and improvements	$ 75,340	$ 3,154	$ -	$ 78,494
Construction in progress	125,237	128,730	(99,703)	154,264
Total nondepreciable utility plant	200,577	131,884	(99,703)	232,758
Nuclear fuel*	177,955	947	(40,115)	138,787
Depreciable utility plant:				
Generation - Fossil	1,657,365	20,784	(2,217)	1,675,932
Generation - Nuclear	1,338,780	4,605	(1,499)	1,341,886
Transmission	1,347,106	34,171	(3,760)	1,377,517
Distribution	248,116	14,833	(9,940)	253,009
General	348,751	20,165	(3,713)	365,203
Total depreciable utility plant	4,940,118	94,558	(21,129)	5,013,547
Less reserve for depreciation	(2,756,094)	(117,321)	21,129	(2,852,286)
Depreciable utility plant, net	2,184,024	(22,763)	-	2,161,261
Utility plant activity, net	$ 2,562,556	$ 110,068	$ (139,818)	$ 2,532,806

* Nuclear fuel decreases represented amortization of $40.1 million.

5. LONG-TERM CAPACITY CONTRACTS:

Long-term capacity contracts include the District's share of the construction costs of Omaha Public Power District's ("OPPD") 664-megawatt ("MW") Nebraska City Station Unit No. 2 ("NC2") coal-fired power plant. The District has a participation power agreement with OPPD for a 23.7% share of the power from this plant. NC2 began commercial operation on May 1, 2009, at which time the District began amortizing the amount of the capacity contract associated with the plant on a straight-line basis over the 40-year estimated useful life of the plant. Accumulated amortization was $53.2 million and $48.8 million as of December 31, 2020 and 2019, respectively. The unamortized amount of the plant capacity contract was $125.3 million and $130.0 million as of December 31, 2020 and 2019, respectively, of which $4.4 million was included in Prepayments and other current assets as of December 31, 2020 and 2019. The District's share of NC2 working capital was also included in Prepayments and other current assets and was $7.1 million and $6.9 million as of December 31, 2020 and 2019, respectively.

Long-term capacity contracts also include the District's purchase of the capacity of a 50 MW hydroelectric generating facility owned and operated by The Central Nebraska Public Power and Irrigation District ("Central"). The District is amortizing the contract on a straight-line basis over the 40-year estimated useful life of the facility. Accumulated amortization was $73.5 million and $71.2 million as of December 31, 2020 and 2019, respectively. The unamortized amount of the Central capacity contract was $13.1 million and $15.5 million as of December 31, 2020 and 2019, respectively, of which $2.3 million was included in Prepayments and other current assets as of December 31, 2020 and 2019.

The District has an agreement whereby Central makes available all the production of the facility and the District pays all costs of operating and maintaining the facility plus a charge based on the amount of energy delivered to the District. Power purchased costs related to Central were $2.3 million and $2.2 million in 2020 and 2019, respectively.

6. INVESTMENT IN THE ENERGY AUTHORITY:

The District has an investment in The Energy Authority ("TEA"), a nonprofit corporation headquartered in Jacksonville, Florida, and incorporated in Georgia. TEA provides public power utilities access to dedicated resources and advanced technology systems. The District's interest in TEA is 17.65% as of December 31, 2020 and 2019. In addition to the District, the following utilities have interests of 17.65% each as of December 31, 2020: American Municipal Power, Inc.; JEA (Florida); Municipal Energy Authority of Georgia; and South Carolina Public

Service Authority (a.k.a. Santee Cooper). The following utilities have interests in TEA of 5.875% each as of December 31, 2020: City Utilities of Springfield, Missouri and Gainesville Regional Utilities (Florida).

Such investment was $9.4 million and $7.6 million as of December 31, 2020 and 2019, respectively. TEA's revenues and costs are allocated to members pursuant to Settlement Procedures under the Operating Agreement. TEA is the District's market participant in SPP's Integrated Market and provides the District gas contract management and other services. The District accounts for its investment in TEA under the equity method of accounting.

The District was obligated to guaranty, directly or indirectly, TEA's electric trading activities in an amount up to $53.9 million, at December 31, 2020, which any party claiming and prevailing under the guaranty might incur and be entitled to recover under its contract with TEA. Generally, the District's guaranty obligations for electric trading would arise if TEA did not make the contractually required payment for energy, capacity, or transmission which was delivered or made available or if TEA failed to deliver or provide energy, capacity, or transmission as required under a contract.

The District's exposure relating to TEA is limited to the District's investment in TEA, any accounts receivable from TEA, and trade guarantees provided to TEA by the District. Upon the District making any payments under its electric guaranty, it has certain contribution rights with the other members of TEA in order that payments made under the TEA member guaranties would be equalized ratably, based upon each member's interest in TEA and the guarantees they have provided. After such contributions have been made, the District would only have recourse against TEA to recover amounts paid under the guarantee. The term of this guarantee is generally indefinite, but the District has the right to reduce and/or terminate its guarantee obligations by providing advanced notice to the beneficiaries thereof. Such termination of its guarantee obligations only applies to TEA transactions not yet entered into at the time the termination takes effect. The District did not record any liabilities for these guarantees as of December 31, 2020 and 2019.

Financial statements for TEA may be obtained at The Energy Authority, 301 W. Bay Street, Suite 2600, Jacksonville, Florida, 32202.

7. DEBT:

The following table summarizes debt balances as of December 31, 2020 and 2019, and debt activity for 2020 (in 000's):

	Total Debt at December 31, 2019	Increases	Decreases	Total Debt at December 31, 2020	Long-Term Debt at December 31, 2020	Current Liabilities at December 31, 2020
Revenue bonds	$ 1,417,547	$ 125,825	$ (140,743)	$ 1,402,629	$ 1,323,489	$ 79,140
Revolving credit agreements	227,153	76,105	(167,340)	135,918	21,919	113,999
Total debt activity	$ 1,644,700	$ 201,930	$ (308,083)	$ 1,538,547	$ 1,345,408	$ 193,139

The following table summarizes debt balances as of December 31, 2019 and 2018, and debt activity for 2019 (in 000's):

	Total Debt at December 31, 2018	Increases	Decreases	Total Debt at December 31, 2019	Long-Term Debt at December 31, 2019	Current Liabilities at December 31, 2019
Revenue bonds	$ 1,530,540	$ 132,195	$ (245,188)	$ 1,417,547	$ 1,336,092	$ 81,455
Revolving credit agreements	254,964	28,298	(56,109)	227,153	146,317	80,836
Total debt activity	$ 1,785,504	$ 160,493	$ (301,297)	$ 1,644,700	$ 1,482,409	$ 162,291

Revenue Bonds

In March 2021, the District initiated the preliminary closing on $75.5 million of General Revenue Bonds, 2021 Series A (Forward Delivery) at a premium of $17.3 million, and $52.1 million of General Revenue Bonds, 2021 Series B (Forward Delivery) at a premium of $12.9 million, for the principal purpose of refunding certain of the District's outstanding General Revenue Bonds, 2014 Series A, 2014 Series C, and 2015 Series A-2. The refunding was completed with $157.8 million of the proceeds from the General Revenue Bonds, 2021 Series A and B, and $1.1 million of other available funds. As a result, total debt service payments over the life of the bonds are expected to be reduced by $42.6 million, which will result in total present value savings of $31.0 million. The 2021 Series A and B Forward Delivery transaction has a settlement date of October 2021.

In December 2020, the District redeemed $42.8 million of General Revenue Bonds, 2010 Series C.

In November 2020, the District issued $125.8 million of General Revenue Bonds, 2020 Series A for the principal purpose of financing and refinancing the costs of construction of certain transmission facilities of the District.

The District expects to continue to finance through 2024 from indebtedness a prior year SPP Notice to Construct capital project for approximately 225 miles of 345 kV transmission line (the "R-Project") which has an SPP approved estimated cost of $462.1 million. The District's current estimate for the cost of the construction of the R-Project, including escalation, is $473.1 million. The District previously issued General Revenue Bonds, 2020 Series A to finance a portion of the cost of the R-Project. The District has spent approximately $123.1 million through December 31, 2020, for design, construction mobilization and easement acquisitions.

In October 2019, the District issued $74.7 million of General Revenue Bonds, 2019 Series B-1 (Taxable) and $16.3 million of General Revenue Bonds, 2019 Series B-2 (Taxable) for the principal purpose of refunding certain of the District's outstanding General Revenue Bonds, 2012 Series A, 2014 Series A, 2014 Series C, and 2015 Series A-2. The refunding was completed with $91.0 million of the proceeds from the General Revenue Bonds, 2019 Series B-1 and B-2 and $3.5 million of other available funds. As a result, total debt service payments over the life of the bonds were reduced by $9.9 million, which resulted in total present value savings of $6.0 million.

In January 2019, the District issued $36.0 million of General Revenue Bonds, 2019 Series A, at a premium of $5.2 million, to refund $50.4 million of General Revenue Bonds, 2009 Series A (Taxable Build America Bonds). The refunding was completed with $41.2 million of the proceeds from General Revenue Bonds, 2019 Series A, $3.7 million from the TERCA, and $5.5 million of other available funds. As a result, total debt service payments over the life of the bonds was reduced by $20.4 million, which resulted in present value savings of $6.6 million.

In January 2019, the District defeased certain of the General Revenue Bonds, 2017 Series A, with an outstanding principal amount that aggregated $7.3 million and called the remaining outstanding General Revenue Bonds, 2009 Series C, with a principal amount that aggregated $0.4 million.

Congressional action reduced the 35% interest subsidy, pursuant to the requirements of the Balanced Budget and Emergency Deficit Control Act of 1985, as amended, on the District's 2010 Series A (Taxable Build America Bonds). Reductions were 5.7% and 6.2% for fiscal years ended September 30, 2020 and 2019, respectively.

There were outstanding principal amounts aggregating $93.4 million and $94.1 million from legal defeasances of General Revenue Bonds, 2012 Series A, 2014 Series A, 2014 Series C, 2015 Series A-2, and 2017 Series A, as of December 31, 2020 and 2019, respectively.

The General Bonds are special obligations of the District payable solely by the Pledged Property, which is the revenues and all funds and accounts created under the General Resolution. The General Resolution defines Events of Default which may result in the declaration of the principal of all outstanding General Bonds and the accrued interest to be due and payable immediately. Events of Default include failure to make timely debt service payments, extended defaults in the performance of any debt covenants, and court order relating to bankruptcy or insolvency of the District.

Debt service payments and principal payments of the General Revenue Bonds as of December 31, 2020, are as follows (in 000's):

Year	Debt Service Payments	Principal Payments
2021	$ 133,701	$ 79,140
2022	127,109	76,425
2023	131,066	79,310
2024	136,135	87,510
2025	134,661	89,830
2026-2030	531,944	358,140
2031-2035	404,099	309,740
2036-2040	180,959	143,415
2041-2045	79,814	67,875
2046-2050	26,102	23,305
Total Payments	$ 1,885,590	$ 1,314,690

The fair value of outstanding revenue bonds was determined using currently published rates. The fair value was estimated to be $1,457.0 million and $1,512.0 million as of December 31, 2020 and 2019, respectively.

Tax-Exempt Revolving Credit Agreement
The District entered into a TERCA with two commercial banks to provide for loan commitments to the District up to an aggregate amount not to exceed $150.0 million. The District had an outstanding balance under the TERCA of $21.9 million and $80.8 million as of December 31, 2020 and 2019, respectively. As such, the remaining credit available under TERCA was $128.1 million and $69.2 million as of December 31, 2020 and 2019, respectively. The outstanding amount is anticipated to be retired by future collections through electric rates and the issuance of revenue bonds. The carrying value approximates market value because the agreement was renewed on October 15, 2020, with a termination date of October 13, 2023.

The obligation of the District to pay the principal, interest, bank fees, and expenses pursuant to the TERCA during the revolving credit period is payable from the Pledged Property subject and subordinated to the pledge of the Pledged Property to the payment of the General Bonds. However, if the TERCA is converted to a term loan, the payment obligation of the District under the TERCA would be on a parity with the District's obligation to pay the General Bonds.

The TERCA defines Events of Default which may result in the declaration of the principal and the accrued interest to be due and payable at an earlier date or immediately. Events of Default include failure to make timely debt service payments, extended defaults in the performance of any debt covenants, court order relating to bankruptcy or insolvency of the District, extended failure to pay a final unappealable judgment of $5.0 million or greater, an imposed debt moratorium or comparable restriction on debt service payments, and an extended long-term rating downgrade to below "BBB-" for credit-related reasons.

Taxable Revolving Credit Agreement
The District has entered into a TRCA with two commercial banks to provide for loan commitments to the District up to an aggregate amount not to exceed $200.0 million. The TRCA allows the District to increase the loan commitments to $300.0 million. The District had outstanding balances under the TRCA of $114.0 million and $146.3 million, as of December 31, 2020 and 2019, respectively. As such, the remaining credit available under TRCA, using the allowance to increase the loan commitments to $300.0 million, was $186.0 million and $153.7 million as of December 31, 2020 and 2019, respectively. The outstanding amount is anticipated to be retired by future collections through electric rates. The carrying value approximates market value because the agreement was renewed on July 30, 2018, with a termination date of July 29, 2021. The District expects to renew the TRCA for an additional three years.

The obligation of the District to pay the principal, interest, bank fees, and expenses pursuant to the TRCA during the revolving credit period is payable from the Pledged Property subject and subordinated to the pledge of the Pledged Property to the payment of the General Bonds. However, if the TRCA is converted to a term loan, the payment obligation of the District under the TRCA would be on a parity with the District's obligation to pay the General Bonds.

The TRCA defines Events of Default which may result in the declaration of the principal and the accrued interest to be due and payable immediately and the termination of the Agreement. Events of Default include failure to make timely debt service payments, extended defaults in the performance of any debt covenants, court order relating to bankruptcy or insolvency of the District, extended failure to pay a final unappealable judgment, an imposed debt moratorium or comparable restriction on debt service payments, and an extended long-term rating downgrade to below "BBB-".

Revenue bonds consist of the following (000's except interest rates):

December 31,	Interest Rate	2020	2019
General Revenue Bonds:			
2010 Series A Taxable Build America Bonds:			
Serial Bonds: 2020–2024	3.98% - 4.73%	$ 21,825	$ 26,915
Term Bonds: 2025–2029	5.323%	27,985	27,985
2030–2042	5.423%	54,190	54,190
2010 Series B Taxable Serial Bonds 2020	4.13% - 4.18%	-	970
2010 Series C:			
Serial Bonds: 2020–2025	3.00% - 5.00%	-	27,435
Term Bonds: 2026–2030	4.00%	-	6,165
2026–2030	5.00%	-	14,180
2012 Series A Serial Bonds 2020–2034	3.00% - 5.00%	117,570	126,985
2012 Series B:			
Serial Bonds: 2020–2032	2.875% - 5.00%	55,970	66,015
Term Bonds: 2033–2036	3.625%	2,320	2,320
2037–2042	3.625%	4,155	4,155
2013 Series A Serial Bonds 2028–2033	3.00% - 5.00%	62,680	62,680
2014 Series A:			
Serial Bonds: 2020–2038	3.50% - 5.00%	85,020	96,325
Term Bonds: 2039–2043	4.00%	31,650	31,650
2039–2043	4.125%	1,945	1,945
2014 Series C Serial Bonds 2020–2033	4.00% - 5.00%	63,720	87,435
2015 Series A-1 Serial Bonds 2022–2034	3.00% - 5.00%	119,400	119,400
2015 Series A-2:			
Serial Bonds: 2020–2034	3.00% - 5.00%	49,760	50,260
Term Bonds: 2035–2039	5.00%	46,205	46,205
2016 Series A:			
Serial Bonds: 2024–2035	3.125% - 5.00%	53,665	53,665
Term Bonds: 2036–2040	5.00%	5,595	5,595
2016 Series B:			
Serial Bonds: 2028–2036	5.00%	64,570	64,570
Term Bonds: 2037–2039	5.00%	1,165	1,165
2016 Series C Serial Bonds 2020–2035	4.00% - 5.00%	55,235	59,320
2016 Series D:			
Serial Bonds: 2020–2035	3.00% - 5.00%	18,410	19,290
Term Bonds: 2036–2040	5.00%	9,505	9,505
2041–2045	5.00%	12,140	12,140
2016 Series E Taxable Serial Bonds 2022–2033	2.337% - 3.567%	56,050	56,050
2017 Series A Serial Bonds 2020–2027	2.00% - 5.00%	4,230	5,820
2017 Series B Serial Bonds 2020–2027	5.00%	40,470	47,015
2019 Series A Serial Bonds 2020–2034	5.00%	33,125	34,770
2019 Series B-1 Taxable Serial Bonds 2020–2028	1.986% - 2.593%	74,095	74,650
2019 Series B-2 Taxable Serial Bonds 2020–2028	1.986% - 2.593%	16,215	16,345
2020 Series A Serial Bonds 2024–2050	0.60%	125,825	-
Total par amount of revenue bonds		1,314,690	1,313,115
Unamortized premium net of discount		87,939	104,432
		1,402,629	1,417,547
Less – current maturities of revenue bonds		(79,140)	(81,455)
Long-term revenue bonds		$ 1,323,489	$ 1,336,092

8. PAYMENTS IN LIEU OF TAXES:

The District is required to make payments in lieu of taxes, aggregating 5% of the gross revenue derived from electric retail sales within the city limits of incorporated cities and towns served directly by the District. Such payments totaled $9.8 million and $10.2 million for the years ended December 31, 2020 and 2019, respectively.

9. ASSET RETIREMENT OBLIGATIONS:

Measurement of ARO under GASB guidance is based on the best estimate in today's dollars, or the current value, of cash outlays expected to be incurred in the future. The GASB guidance requires the recognition of a corresponding deferred outflow of resources. The District uses regulatory accounting to align asset retirement costs with their related recognition in rates. The difference in the ARO amounts and the related deferred outflows represents the amounts collected in rates and interest income on decommissioning funds.

AROs as of December 31, are as follows (in 000's):

Description	2020	2019
CNS license termination costs	$ 730,568	$ 846,252
GGS and Sheldon ash landfills	10,228	10,105
Ainsworth	2,064	2,036
Underground storage tanks	1,000	1,000
	$ 743,860	$ 859,393

The District is required by the Nuclear Regulatory Commission ("NRC") to decommission CNS after cessation of plant operations, consistent with regulations in the U.S. Code of Federal Regulations. The CNS license termination costs were based on an external study for costs for three different scenarios: 1) immediate commencement of decommissioning after license termination in 2034; 2) delayed decommissioning for 46 years after license termination; and 3) safe storage for 60 years after license termination. The costs were based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements. An expert panel, consisting of District management representatives with considerable nuclear experience, assigned probabilities to these different scenarios. These weighted probabilities were used when calculating the ARO. The decrease in the CNS license termination costs in 2020 was due primarily to more weighting for scenario one, which has a lower cost. Rates in the consumer price index for all urban consumers ("CPI-U") were used to adjust these obligations for inflation, as the costs in the study were in 2019 dollars for the year ended December 31, 2020 and 2015 dollars for the year ended December 31, 2019. The inflation rates used were 1.36% and 2.29% for the years 2020 and 2019, respectively. The District has funds set aside for decommissioning of $706.2 million and $652.7 million as of December 31, 2020 and 2019, respectively. These funds exceeded the NRC's required funding provisions for nuclear decommissioning.

The District is required by the Environmental Protection Agency ("EPA") and the Nebraska Department of Environment & Energy ("NDEE") to decommission the ash landfills at GGS and Sheldon, consistent with their regulations. As GASB guidance is unclear related to the accounting treatment for ash landfill AROs, GASB Statement No. 83, *Certain Asset Retirement Obligations*, was considered analogous authoritative literature and applied in this situation. The ash landfills have an estimated closure date in the years 2086 and 2034 for GGS and Sheldon, respectively. The AROs were based on external studies to estimate costs using one scenario after an assessment of the physical site. The closure and post-closure costs were based on the Closure Plan in the studies and included final cover placements and lined surface water control structures. The costs in the latest studies were in 2019 and 2017 dollars for GGS and Sheldon, respectively. The rate of 1.36% in the CPI-U was used to adjust for inflation in 2020. The inflation rate of 1.75% used to adjust the Sheldon obligation for 2019 was provided by the NDEE. The District provides guarantees and financial assurance through correspondence and supporting information to NDEE annually. The District included in rates decommissioning costs for certain assets at GGS and Sheldon. The costs included in rates for the decommissioning of the ash landfills were $1.0 million and $0.4 million for 2020 and 2019, respectively. These rate collections reduced the related deferred outflow for the ash landfills.

The District is required by contracts with the landowners of the Ainsworth Wind Energy Facility ("Ainsworth") site to restore the property, as nearly as possible, to the condition it was in prior to the District's use of the easement. Ainsworth has an estimated closure date of September 30, 2025. The ARO was based on an external study for costs using one scenario. The assumptions included: 1) no hazardous construction material abatement is required; 2) no environmental costs to address site clean-up; 3) floor drain and septic tanks will be decommissioned per state regulations; 4) wind turbine nacelles, turbine towers, transformers and other electrical equipment are removed from the site by the demolition contractor; 5) the O&M buildings and one onsite meteorological tower were included with the demolition costs; 6) all foundations will be removed to two feet below finished grade; and 7) all concrete and crushed rock surfacing will be removed. The costs in the study were in 2015 dollars. Rates in the CPI-U were used to adjust these obligations for inflation. The inflation rates used were 1.36% and 2.29% for the years 2020 and 2019, respectively. There are no legally required funding and assurance provisions associated with this ARO. The costs included in rates for the decommissioning of Ainsworth were $0.2 million for both 2020 and 2019. These rate collections reduced the related deferred outflow for Ainsworth.

The District is required by the NDEE to decommission the underground storage tanks at various locations in the District's service area, consistent with its regulations. The remaining lives of the storage tanks cannot be reasonably estimated. The AROs were based on the best estimate of District management representatives with expertise in environmental issues. The District provided guarantees and financial assurance through correspondence and supporting information to NDEE annually. There have not been any decommissioning costs for the underground storage tanks included in rates.

10. RETIREMENT PLAN:

The District's Employees' Retirement Plan (the "Plan") is a defined contribution 401(k) pension plan established and administered by the District to provide benefits at retirement to regular full-time and part-time employees. There were 1,915 and 1,888 active Plan members as of December 31, 2020 and 2019, respectively. Plan provisions and contribution requirements are established and may be amended by the Board.

Plan members are eligible to begin participation in the Plan immediately upon hire. Contributions ranging from 2% to 5% of base pay are eligible for District matching dollars after six months of employment. The District contributes two times the Plan member's contribution based on covered salary up to $75,000. On covered salary greater than $75,000, the District contributes one times the Plan member's contribution. The Participants' contributions were $16.5 million and $15.3 million for 2020 and 2019, respectively. The District's matching contributions were $15.6 million and $15.2 million for 2020 and 2019, respectively. Total contributions of $1.6 million were accrued in Accounts payable and accrued liabilities for the years ended December 31, 2020 and 2019.

Plan members are immediately vested in their own contributions and earnings and become vested in the District's contributions and earnings based on the following vesting schedule:

Years of Vesting Participation	Percent
5 years or more	100%
4 years	75%
3 years	50%
2 years	25%
Less than 2 years	0%

Nonvested District contributions are first used to cover Plan administrative expenses and any remaining forfeitures are allocated back to Plan participants.

Employees may also contribute to an eligible deferred compensation plan which is intended to meet the requirements of Code Section 457(b) ("457(b) Plan"). The 457(b) Plan is a defined contribution plan which permits Pre-tax and Roth elective deferral contributions. The Plan does not provide for a District match but does permit discretionary non-elective contributions by the District. Participants may change their elective deferrals at any time. Early withdrawals can be made from the 457(b) Plan following separation of service regardless of age with no IRS penalty. Income taxes are owed on any withdrawals of Pre-tax elective deferral contributions and discretionary non-elective contributions. Income taxes are not owed on withdraws of Roth elective deferral contributions if certain requirements are met. The total contributions to the 457(b) Plan were $2.5 million and $2.3 million for 2020 and 2019, respectively.

11. OTHER POSTEMPLOYMENT BENEFITS:

A. *General information regarding the OPEB Plan –*

Plan Description

The District's Postemployment Medical and Life Benefits Plan ("Plan") provides postemployment hospital-medical and life insurance benefits to qualifying retirees, surviving spouses, and employees on long-term disability and their dependents. Benefits and related eligibility, funding and other Plan provisions, for this single-employer, defined benefit Plan, are authorized by the Board. The Plan is administered by the District.

The Plan has been amended over the years and provides different benefits based on hire date and/or the age of the employee. These benefits include a self-insured plan, a group-insured Medicare Part D supplement, and a Retiree Reimbursement Account ("RRA"). The RRA was approved by the Board in January 2020 with an effective date of January 1, 2021. The addition of the RRA expanded the availability of benefits to post-age 65 retirees hired from January 1, 1999 through December 31, 2003, and retirees hired on or after January 1, 2004. The RRA provides reimbursements for applicable healthcare premiums up to an annual amount of $4,000 and $2,000 for pre-age 65 and post-age 65 retirees, respectively. As these benefits, were not effective until January 1, 2021, they were not included in the actuarial valuation as of January 1, 2020. The District also provides a postemployment death benefit for $5,000 for qualifying employees.

Employees Covered by Benefit Terms

Hired Prior to January 1, 1993	District and retiree share in premium costs for retiree and dependents prior to age 60; District pays 100% of premiums at age 60 and after
Hired January 1, 1993 to December 31, 1998	District and retiree share in premium costs for retiree and dependents until age 65; District share of premiums capped at age 65
Hired January 1, 1999 to December 31, 2003	District and retiree share in premium costs for retiree and dependents until age 65; For employees active as of January 1, 2020, retiree eligible for RRA at age 65 and after
Hired January 1, 2004 and after	For employees active as of January 1, 2020, retiree eligible for RRA

Employees Covered by Benefit Terms

The following table shows the employees covered by the hospital-medical benefit terms as of January 1:

	2020	2019
Active employees	878	934
Inactive employees in retirement status	1,392	1,370
Inactive employees in long-term disability status	48	56
Total employees covered by benefit terms	2,318	2,360

The following table shows the employees covered by the life insurance benefit terms as of January 1:

	2020	2019
Active employees	1,888	1,902
Inactive employees in retirement status	1,230	1,213
Inactive employees in long-term disability status	56	65
Total employees covered by benefit terms	3,174	3,180

Contributions
The Board annually approves the funding for the Plan, which has a minimum funding requirement of the actuarially-determined annual required contribution to achieve full funding status on or before December 31, 2033. The District OPEB contributions were $28.3 million and $41.1 million in 2020 and 2019, respectively. The 2019 contributions included additional contributions for prior employee service of $12.8 million in 2019 for the transmission and retail levels of service.

Contributions from Plan members are the required premium share for inactive members, which is based on hire date and/or age. Contributions from Plan members were $0.6 million and $0.7 million for 2020 and 2019, respectively. As these contributions were from inactive members, they were reported as a reduction of benefit expenses. Members do not contribute to the cost of the life insurance benefits.

B. *Net OPEB Liability –*
The District's net OPEB liability was measured as of January 1, 2020, and January 1, 2019, and the total OPEB liability used to calculate the net OPEB liability was determined by an actuarial valuation as of these dates.

Actuarial Assumptions and Methods
The actuarial assumptions and methods used in the January 1, 2020 actuarial valuation were based on the results of an actuarial experience study completed during 2018. The total OPEB liability in the January 1, 2020, actuarial valuation was determined using the following actuarial assumptions and methods, applied to all periods included in the measurement, unless otherwise specified:

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	13-year closed period
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 7.1% initial, ultimate 4.5% Post-Medicare: 7.8% initial, ultimate 4.5%
Administrative cost trend	3.0%
Inflation	2.2%
Salary increases	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Discount rate	6.25%, based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	Pub-2010 "General" table with generational projection using Scale MP-2019
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 60% of females are assumed to have spouses who will elect coverage. Males are assumed to be two years older than their spouses. Females are assumed to be two years younger.
Participation rate	95.0%

The actuarial assumptions used in the January 1, 2019 actuarial valuation were based on the results of an actuarial experience study completed during 2018. The total OPEB liability in the January 1, 2019, actuarial valuation was determined using the following actuarial assumptions and methods, applied to all periods included in the measurement, unless otherwise specified:

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	14-year closed period
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 7.4% initial, ultimate 4.5% Post-Medicare: 8.2% initial, ultimate 4.5% Included impact of the excise tax (not repealed until 12/2019)
Administrative cost trend	3.0%
Inflation	2.3%
Salary increases	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Discount rate	6.25%, based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	Pub-2010 "General" table with generational projection using Scale MP-2018
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 60% of females are assumed to have spouses who will elect coverage. Males are assumed to be two years older than their spouses. Females are assumed to be two years younger.
Participation rate	95.0%

The long-term expected rate of return on OPEB Plan investments was determined using a building-block method in which best-estimate ranges of expected future rates of return (expected returns, net of OPEB Plan investment expense and inflation) are developed for each major asset class. These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation. The target allocation and best estimates of geometric real rates of return for each major asset class are summarized in the following table for the valuation measurement date of January 1:

Asset Class	Target Allocation	2020 Long-Term Expected Real Rate of Return
Equity (1)	70%	7.2%
Fixed income	30%	3.0%
	100%	6.2%

Asset Class	Target Allocation	2019 Long-Term Expected Real Rate of Return
Equity (1)	70%	7.4%
Fixed income	30%	3.6%
	100%	6.5%

(1) The actuary included the 10% real estate allocation with equity.

Discount Rate

The discount rate used to measure the total OPEB liability was 6.25% for the actuarial valuations as of January 1, 2020 and 2019. The projection of cash flows used to determine the discount rate assumed that contributions will be made at rates equal to the actuarially-determined contribution rates. Based on those assumptions, the Plan's fiduciary net position was projected to be available to make all projected benefit payments for current active and inactive employees. Therefore, the long-term expected rate of return on Plan investments was applied to all periods of projected benefit payments to determine the total OPEB liability.

C. Changes in the Net OPEB Liability –

The following table shows the Total OPEB Liability, Plan Fiduciary Net Position and Net OPEB Liability as of January 1, 2020, and the changes during this period, based on the valuation measurement date of January 1, 2020 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB Liability (a-b)
Balances at January 1, 2019	$ 317,672	$ 212,438	$ 105,234
Changes for the year:			
Service cost	2,299	-	2,299
Interest	19,604	-	19,604
Differences between expected and actual experience	(19,961)	-	(19,961)
Changes of assumptions	(1,607)	-	(1,607)
Contributions - employer	-	41,084	(41,084)
Net investment income	-	41,733	(41,733)
Benefit payments	(12,807)	(12,807)	-
Administrative expense	-	(188)	188
Net changes	(12,472)	69,822	(82,294)
Balances at January 1, 2020	$ 305,200	$ 282,260	$ 22,940

There were changes made in certain assumptions for the valuation measurement date of January 1, 2020. The mortality assumptions were updated to the Pub-2010 "General" table with generational projection using Scale MP-2019. The healthcare trend rates were also updated.

Sensitivity of the Net OPEB Liability to Changes in the Discount Rate

The following table shows the net OPEB liability of the District, as well as what the net OPEB liability would be if it were calculated using a discount rate that is 1-percentage-point lower (5.25%) or 1-percentage-point higher (7.25%) than the discount rate (6.25%) at the measurement date of January 1, 2020 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB Liability	$ 60,039	$ 22,940	$ (8,114)

Sensitivity of the Net OPEB Liability to Changes in the Healthcare Cost Trend Rates

The following table shows the net OPEB liability of the District, as well as what the net OPEB liability would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 6.1% initial to 3.5% ultimate, Post-Medicare ranging from 6.8% initial to 3.5% ultimate) or 1- percentage-point higher (Pre-Medicare ranging from 8.1% initial to 5.5% ultimate, Post-Medicare ranging from 8.8% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 7.1% initial to 4.5% ultimate, Post-Medicare ranging from 7.8% initial to 4.5% ultimate) at the measurement date of January 1, 2020 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB Liability	$ (6,864)	$ 22,940	$ 58,341

The following table shows the Total OPEB Liability, Plan Fiduciary Net Position and Net OPEB Liability as of January 1, 2019, and the changes during this period, based on the valuation measurement date of January 1, 2019 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB Liability (a-b)
Balances at January 1, 2018	$ 318,737	$ 176,814	$ 141,923
Changes for the year:			
Service cost	2,771	-	2,771
Interest	19,661	-	19,661
Differences between expected and actual experience	(8,686)	-	(8,686)
Changes of assumptions	(751)	-	(751)
Contributions - employer	-	56,706	(56,706)
Net investment income	-	(6,892)	6,892
Benefit payments	(14,060)	(14,060)	-
Administrative expense	-	(130)	130
Net changes	(1,065)	35,624	(36,689)
Balances at January 1, 2019	$ 317,672	$ 212,438	$ 105,234

There were changes made in certain assumptions for the valuation measurement date of January 1, 2019. The mortality assumptions were updated to the Pub-2010 "General" table with generational projection using Scale MP-2018. The healthcare trend rates were also updated. Demographic assumptions updated as a result of an actuarial experience study performed in 2018 included: retirement rates, withdrawal rates, retiree healthcare participation rate, spouse coverage election percentage, and spouse age differential.

Sensitivity of the Net OPEB Liability to Changes in the Discount Rate

The following table shows the net OPEB liability of the District, as well as what the net OPEB liability would be if it were calculated using a discount rate that is 1-percentage-point lower (5.25%) or 1-percentage-point higher (7.25%) than the discount rate (6.25%) at the measurement date of January 1, 2019 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB Liability	$ 144,753	$ 105,234	$ 72,256

Sensitivity of the Net OPEB Liability to Changes in the Healthcare Cost Trend Rates

The following table shows the net OPEB liability of the District, as well as what the net OPEB liability would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 6.4% initial to 3.5% ultimate, Post-Medicare ranging from 7.2% initial to 3.5% ultimate) or 1-percentage-point higher (Pre-Medicare ranging from 8.4% initial to 5.5% ultimate, Post-Medicare ranging from 9.2% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 7.4% initial to 4.5% ultimate, Post-Medicare ranging from 8.2% initial to 4.5% ultimate) at the measurement date of January 1, 2019 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB Liability	$ 73,323	$ 105,234	$ 143,313

OPEB Plan Fiduciary Net Position
Detailed information about the OPEB Plan Fiduciary Net Position is available in separately issued audited financial statements for Nebraska Public Power District Postemployment Medical and Life Benefits Plan available on the District's website, NPPD.com.

D. OPEB Expense, Deferred Outflows of Resources and Deferred Inflows of Resources Related to OPEB –
The Board annually approves the OPEB expense in rates and has authorized the use of regulatory accounting to equate OPEB expense with the amount in rates. OPEB expense was negative $3.2 million for 2020, as calculated under the GASB Statement No. 75 guidance, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pension Plans,* which is largely due to the expected investments returns and amortization exceeding the service and interest costs. With regulatory accounting, OPEB expense and the amount included in rates was $28.3 million for 2020. The regulatory accounting OPEB expense is higher because it includes the amortization of costs related to prior periods.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2020 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ 813	$ 40,220
Changes in assumptions	-	1,911
Difference between actual and expected earnings	11,328	27,143
Contributions made during the year ended December 31, 2020	28,283	-
	$ 40,424	$ 69,274

The deferred outflows of resources related to the contributions made during the year ended December 31, 2020 will be recognized in the actuarial valuation with a measurement date of January 1, 2021. The net of the other deferred outflows and deferred inflows of resources will be recognized as a reduction in OPEB expense as follows (in 000's):

Year	Amount
2021	$ (12,389)
2022	(13,151)
2023	(10,816)
2024	(13,293)
2025	(4,671)
2026	(2,813)
Total	$ (57,133)

OPEB expense was $8.0 million for 2019, as calculated under the GASB Statement No. 75 guidance. With regulatory accounting, OPEB expense and the amount included in rates was $41.1 million for 2019. The regulatory accounting OPEB expense is higher because it includes the amortization of costs related to prior periods, including a $12.8 million catch-up rate collection for the net OPEB liability for transmission and retail levels of services of $10.0 million and $2.8 million, respectively.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2019 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ 1,552	$ 28,897
Changes in assumptions	-	644
Difference between actual and expected earnings	16,134	7,227
Contributions made during the year ended December 31, 2019	41,084	-
	$ 58,770	$ 36,768

The deferred outflows of resources related to the contributions made during the year ended December 31, 2019 were recognized in the actuarial valuation with a measurement date of January 1, 2020. The net of the other deferred outflows and deferred inflows of resources will be recognized as a reduction in OPEB expense as follows (in 000's):

Year	Amount
2020	$ (2,717)
2021	(3,682)
2022	(4,444)
2023	(2,109)
2024	(4,585)
2025	(1,545)
Total	$ (19,082)

Additional information is available in the unaudited Required Supplementary Information section following the Notes to Financial Statements.

12. COMMITMENTS AND CONTINGENCIES:

A. *Fuel Commitments –*

The District has various coal supply contracts with minimum estimated future payments of $160.0 million at December 31, 2020. These contracts expire at various times through the end of 2023. The coal transportation contract in place is sufficient to deliver coal to the generation facilities through and beyond the expiration date of the aforementioned contracts and is subject to price escalation adjustments.

The District has a contract for conversion services of uranium to uranium hexafluoride which is in effect through 2021, a contract for enrichment services and a contract for fabrication services through January 18, 2034, the end of the current operating license of CNS. These commitments for nuclear fuel material and services have combined estimated future payments of $205.0 million, if needed.

B. *Power Purchase and Sales Agreements –*

The District has entered into a participation power agreement (the "NC2 Agreement") with OPPD to purchase 23.7% of the power of NC2, estimated to be 157 MW of the power from the 664 MW coal-fired power plant constructed by OPPD. The initial term of the agreement is for 40 years following the Commercial Operation date, which was in May 2009.The NC2 Agreement contains a step-up provision obligating the District to pay a share of the cost of any deficit in funds for operating expenses, debt service, other costs, and reserves related to NC2 in the event of a defaulting power purchaser. The District's obligation pursuant to such step-up provision is limited to 160% of its original participation share. No such default has occurred to date.

The District has entered into a participation power sales agreement with Municipal Energy Agency of Nebraska ("MEAN") for the sale to MEAN of the power and energy from GGS and CNS of 50 MW which began January 1, 2011 and continues through December 31, 2023.

The District has entered into power sales agreements with Lincoln for the sale to Lincoln of 8% of the net power and energy of GGS. In return, Lincoln agrees to pay 8% of all costs attributable to GGS. This agreement is to terminate upon the later of the last maturity of the debt attributable to GGS or the date on which the District retires such station from commercial operation.

The District has wholesale power purchase commitments with Western which consist of 148.5 MW of firm power and 287 MW of firm peaking power from the Upper Great Plains Region through 2050, and approximately 4 MW of firm power from the Rocky Mountain Region through 2054. The District also receives and pays for approximately 4 MW of firm power from the Upper Great Plains Region for pass through to four Native American tribes through 2050. The annual minimum future payments of these wholesale purchase commitments are approximately $27.6 million.

The District owns and operates the 60 MW Ainsworth Wind Energy Facility and has 20-year participation power agreements to sell 18 MW to three other utilities, a reduction of 10 MW from 2019, as JEA terminated its agreement effective December 31, 2019. In addition, the District has power purchase agreements with seven wind facilities having a total capacity of 435 MW. These agreements are for terms ranging from 20 to 25 years and require the District to purchase all the electric power output of these wind facilities. The District has entered into power sales agreements to sell 154 MW of this capacity to four other utilities in Nebraska over similar terms.

The District has entered into a power purchase agreement with Central for the purchase of the net power and energy produced by the Kingsley Project during its operating life. The Kingsley Project is a hydroelectric generating unit at the Kingsley Dam in Keith County, Nebraska with an accredited net capacity of 37 MW.

The District has entered into long-term PRO Agreements with 79 municipalities for the operation of certain retail electric distribution systems. Seventy-seven of these municipalities have renewed or enhanced their PRO Agreements with terms of 20 or 25 years expiring between 2038 and 2044. These 77 retail PRO Agreement customers represented 70.9 percent of retail revenues for 2020. The remaining two PRO Agreements are being actively worked for renewal and expire in 2029 and 2031. These PRO Agreements obligate the District to make payments based on gross revenues from the municipalities and pay for normal property additions during the term of the agreement.

C. *Wholesale Power Contracts* –

The District serves its wholesale customers under total requirements contracts that require them to purchase total demand and energy requirements from the District, subject to certain exceptions. In 2016, the District entered into 20-year Wholesale Power Contracts (“2016 Contracts”) with 22 public power districts, one cooperative, and 37 municipalities. One public power district and 9 municipalities are served under the 2002 Contracts (“2002 Contracts”), which expire on December 31, 2021.

The 2016 Contracts allow a wholesale customer to give notice to reduce its purchase of demand and energy requirements from the District based on a comparison of the District’s average annual wholesale power costs in a given year compared to power costs of U.S. utilities for such year listed in the National Rural Utilities Cooperative Finance Corporation Key Ratio Trend Analysis (Ratio 88) (the “CFC Data”). The CFC Data places a utility’s power costs in percentiles so that any given utility can compare its power costs on a percentile basis to the CFC published quartile information. The 2016 Contracts allow a wholesale customer to reduce its demand and energy purchases from the District if the District’s average annual wholesale power costs percentile level for a given year is higher than the 45th percentile level (the “Performance Standard Percentile”) of the power costs of U.S. utilities for such year as listed in the CFC Data. The 2016 Contracts would not allow any reductions in demand and energy purchases by a wholesale customer as long as the District’s average annual wholesale power costs percentile remains below the Performance Standard Percentile.

The following table lists the District's wholesale power costs percentile for the calendar years 2013 to 2019 set forth in the CFC Data:

CFC Data	
Year	Percentile
2013	31.0%
2014	27.6%
2015	31.3%
2016	28.2%
2017	26.0%
2018	26.9%
2019	29.5%

The District has ten wholesale customers remaining on the 2002 Contracts. The 2002 Contracts allow a wholesale customer to reduce its purchases of demand and energy upon giving appropriate notice. Reductions could amount to as much as 90% of their demand and energy requirements under certain circumstances. All wholesale customers under the 2002 wholesale contracts are required to purchase at least 10% of their demand and energy from the District through December 31, 2021.

The District has received notices from all wholesale customers under the 2002 Contracts as to their intent to level off, reduce, or terminate the requirements for various amounts from 2017 through 2021. These wholesale customers represented 0.7% and 1.8% of operating revenues for 2020 and 2019, respectively. The District expects that no requirements of said wholesale customers will be served by the District in 2022, and such wholesale customers will purchase all of their electric requirements from other suppliers. The District expects to sell the energy not sold to such wholesale customers into the SPP Integrated Market and continues to explore additional firm requirement and/or fixed price agreements.

The 2016 wholesale rates resulted in a 0.6% increase for wholesale customers who signed the 2016 Contracts, and a 3.8% increase for those wholesale customers who remained under the 2002 Contracts. Customers under the 2002 Contracts will pay their share of previously incurred OPEB costs (or the catch-up amount) through rates prior to the expiration of their contracts in 2021. Customers under the 2016 Contracts received a discount for the deferral of OPEB collections, extending those collections into the new contract period and resulting in the lower net wholesale rate increase. The District financed with taxable debt the 2016 Contracts customers' share of the OPEB catch-up amount for 2016, 2017 and 2018. The customers under the 2016 Contracts will commence payment of the related debt service beginning in 2022, the year after the expiration of the 2002 Contracts.

D. *SPP Membership and Transmission Agreements –*
The District is a member of SPP, a regional transmission organization based in Little Rock, Arkansas. Membership in SPP provides the District reliability coordination service, generation reserve sharing, regional tariff administration, including generation interconnection service, network, and point-to-point transmission service, and regional transmission expansion planning. On March 1, 2014, SPP commenced a Day-Ahead, Ancillary Services, and Real-Time Balancing Market Integrated Market. The Integrated Market also provides a financial market to hedge unplanned transmission congestion, or financial virtual products to hedge uncertainties, such as unplanned outages.

The District entered into a Transmission Facilities Construction Agreement effective June 15, 2009, with TransCanada Keystone Pipeline, LP ("Keystone"). This agreement addresses the transmission facilities, construction, cost allocation, payment, and applicable cost recovery for the interconnection and delivery facilities required for the interconnection of Keystone to the District's transmission system. Cost of the project was $8.4 million and repayment by Keystone, over a 10-year period, began in June 2010. As of December 31, 2019, there was a remaining balance due to the District of $0.5 million. The balance was paid in 2020.

The District has received an SPP Notice to Construct the R-Project, which allows the cost of construction to be included in SPP annual revenue requirements. The R-Project consists of the construction of approximately 225 miles of 345 kV transmission line from GGS, north to a new substation in Holt County interconnected to an existing 345 kV line owned by Western. The R-Project will strengthen the reliability of the District's transmission system, reduce transmission congestion, and allow for the integration of future renewable generation in an area of the state that lacks transmission access. In November 2020, SPP approved the estimated cost of the R-Project at $462.1 million. The estimated cost of the R-Project so approved by SPP became the new baseline for the R-Project. This estimated did not include any escalation of costs for a two-year delay assumed by the District in developing its current estimated cost of construction of the R-Project. SPP will adjust the baseline for escalation on an annual basis. The District's current estimate for the cost of the construction of the R-Project, including escalation, is $473.1 million, which assumes a two-year delay. The District awarded a contract for the construction of the R-Project in January 2019. The District is managing the authorized expenditures and work performed. The District spent approximately $123.1 million through December 31, 2020, for design, construction mobilization and easement acquisitions.

E. *Cooper Nuclear Station –*
On November 29, 2010, the NRC formally issued a certificate to the District to commemorate the renewal of the operating license for CNS for an additional 20 years until January 18, 2034. CNS entered the 20-year period of extended operation on January 18, 2014.

In October 2003, the District entered into an agreement (the "Entergy Agreement") for support services at CNS with Entergy Nuclear Nebraska, LLC ("Entergy"), a wholly owned indirect subsidiary of Entergy Corporation. In 2010, the Entergy Agreement was amended and extended by the parties until January 18, 2029, subject to either party's right to terminate without cause by providing notice and paying a $20.0 million termination charge. Subsequently, the parties amended the agreement in 2017 restricting the ability to terminate without cause for a five-year period ending December 2022. In exchange for the limitation to terminate without cause, the management fee schedule was decreased by 18% during the five-year period. The Entergy Agreement requires the District to reimburse Entergy's cost of providing services, and to pay Entergy annual management fees. These annual management fees were $16.1 million for both 2020 and 2019. These fees will increase by an additional $3.5 million and $3.0 million in 2023 and 2024, respectively. Under the amended Entergy Agreement, Entergy can also earn additional annual incentive fees of up to $4.0 million per year, with the exception of the years 2018-2022 where the amount is limited to $3.5 million per year, if CNS achieves identified safety and regulatory performance targets. Entergy has achieved certain safety and regulatory performance targets during the term of the Entergy Agreement and has been eligible for at least a portion of this annual incentive fee.

CNS substantially completed the construction of a dry cask used fuel storage project in December 2009 to support plant operations until 2034, which is the end of the operating license. The first loading campaign was completed in January 2011 and encompassed the loading of 488 used fuel assemblies from the CNS used fuel pool into eight dry used fuel storage casks for on-site storage. A second loading campaign, encompassing the loading of 610 used fuel assemblies into ten dry used fuel storage casks, began in April 2014 and was completed in June 2014. The third loading campaign, encompassing the loading of 732 used fuel assemblies into 12 dry used fuel storage casks, began in June 2017 and was completed in November 2017. The fourth loading campaign is expected in 2025.

As part of various disputed matters between GE and the District, GE has agreed to continue to store at the Morris Facility the spent nuclear fuel assemblies from the first two full core loadings at CNS at no additional cost to the District until the expiration of the current NRC license in May 2022 for the Morris Facility. After that date, storage would continue to be at no cost to the District as long as GE can maintain the NRC license for the Morris Facility on essentially the existing design and operating configuration.

As a result of the failure of the DOE to dispose of spent nuclear fuel from CNS as required by contract, the District commenced legal action against the DOE on March 2, 2001. The initial settlement agreement addressed future claims through 2013. On January 13, 2014, the District and the DOE agreed to extend the settlement agreement through 2016. On March 2, 2017, the District and the DOE agreed to extend the settlement agreement through 2019. Settlements from the DOE for damages totaled $139.9 million for the years 2009 through 2020. The District accepted the DOE's offer of $6.7 million for the 2019 claim, and the funds were received in October 2020. In September 2020, the District and the DOE agreed to an additional three-year extension of the settlement or years

2020 through 2022. The District also reserves the right to pursue future damages through the contract claims process. A corresponding regulatory liability for these DOE receipts was established in Other deferred inflows of resources. The District plans to use the funds to pay for costs related to CNS. The balance in the regulatory liability was $78.3 million and $72.0 million as of December 31, 2020 and 2019, respectively.

Under the terms of the DOE contracts, the District was also subject to a one mill per kilowatt-hour ("kWh") fee on all energy generated and sold by CNS, which was paid on a quarterly basis to DOE. The District includes a component in its wholesale and retail rates for the purpose of funding the costs associated with nuclear fuel disposal. While the District expects that the revenues developed therefrom will be sufficient to cover the District's responsibility for costs currently outlined in the Nuclear Waste Policy Act, the District can give no assurance that such revenues will be sufficient to cover all costs associated with the disposal of used nuclear fuel. On May 9, 2014, the DOE provided notice that they would adjust the spent fuel disposal fee to zero mills per kWh effective May 16, 2014. Correspondingly, no additional payments have been made to the DOE for fuel disposal since that date. The Board authorized the continued collection of this fee at the same rate. This approach ensures costs are recognized in the appropriate period with current customers receiving the benefits from CNS paying the appropriate costs. The expense for spent nuclear fuel disposal is recorded based on net electricity generated and sold and the regulatory liability will be eliminated when payments are made for spent nuclear fuel disposal.

Under the provisions of the Federal Price Anderson Act, the District and all other licensed nuclear power plant operators could each be assessed for claims in amounts up to $137.6 million per unit owned in the event of any nuclear incident involving any licensed facility in the nation, with a maximum assessment of $20.5 million per year per incident per unit owned.

The NRC evaluates nuclear plant performance as part of its reactor oversight process ("ROP"). The NRC has five performance categories included in the ROP Action Matrix Summary that is part of this process. As of December 31, 2020, CNS was in the Licensee Response Column, which is the first or best of the five NRC defined performance categories and has been in this column since the first quarter of 2012.

Refueling and maintenance outages are required to be performed at CNS approximately every two years. The most recent refueling and maintenance outage began on September 26, 2020 and was completed on October 27, 2020. During this outage, in addition to replacing 180 fuel assemblies and conducting routine maintenance and inspections, the reactor recirculation motor generator was replaced, a condensate and a condensate booster pump was overhauled, and valve replacements occurred in the service water to turbine equipment cooling system. Also, ultrasonic testing of the core shroud occurred, as well as diver cleaning and inspection of the torus.

Significant operations and maintenance expenses are incurred in an outage year. The Board has authorized the collection of these costs over a multi-year period to levelize revenue requirements for expenses and help ensure the customers receiving the benefits from CNS are paying the costs. The regulatory liability for the pre-collection of outage costs was $21.0 million as of December 31, 2019 and was eliminated through revenue recognition during the 2020 outage year.

F. *Environmental* –

Water

The Federal Clean Water Act contains requirements with respect to effluent limitations relating to the discharge of any pollutant and to the environmental impact of cooling water intake structures. The NDEE establishes the requirements for the District's compliance with the Clean Water Act through issuance of National Pollutant Discharge Elimination System permits. NDEE issued the District permits for the following facilities: GGS, Sheldon, CNS, Beatrice Power Station, Kearney Hydro and the North Platte Office Building. The District anticipates some level of fish protection equipment technology installation only for impingement at GGS and CNS. Until the final compliance options are determined, the District does not know the financial impact of this regulation.

On January 2, 2016, the final Steam Electric Power Plant Effluent Guidelines rule (the "Effluent Rule") became effective. The Effluent Rule revises the technology-based effluent limitation guidelines and standards that would strengthen the existing controls on discharges from steam electric power plants and sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. Generally, the Effluent Rule establishes new or additional requirements for wastewater streams from the following processes and byproducts associated with steam electric power generation: flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke. While the District facilities subject to the Effluent Rule are CNS, GGS, Sheldon and Canaday Station, the Effluent Rule only has an impact on Sheldon. Sheldon will be required to comply with the Effluent Rule only for its bottom ash transport water. On August 31, 2020, the EPA Administrator signed the Steam Electric Reconsideration Rule, which modifies the existing Effluent Rule and allows for three separate compliance options. The compliance dates have been extended to December 31, 2025 and December 31, 2028 depending on the option selected. The District is currently analyzing the new options for compliance.

Acid Rain Program

The Clean Air Act Amendments Title IV established a regulatory program, known as the Acid Rain Program, to address the effects of acid rain and impose restrictions on sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") emissions. Acid Rain Permits have been issued for the following facilities: GGS, Sheldon, Canaday Station and Beatrice Power Station. The Acid Rain Permits allow for the discharge of SO_2 at each facility pursuant to an allowance system. Based on current generation projections through 2026, the District expects to have sufficient Acid Rain allowances to cover affected facilities through 2026, but may be required to purchase additional allowances in the future.

Mercury and Air Toxic Standards

On February 16, 2012, the EPA issued a final rule intended to reduce emissions of toxic air pollutants from power plants. Specifically, the Mercury and Air Toxics Standards ("MATS") Rule requires reductions in emissions from new and existing coal- and oil-fired steam utility electric generating units of toxic air pollutants. The affected District facilities, which are GGS and Sheldon, are in compliance with the MATS Rule.

Cross-State Air Pollution Rule

The EPA issued a rule in 2012 which is referred to as the Cross-State Air Pollution Rule ("CSAPR") that would require significant reductions in SO_2 and NO_x emissions in a number of states, including Nebraska. CSAPR compliance periods went into effect on January 1, 2015. Based on the current CSAPR allocation methodology and current generation projections through 2026, the District expects to have sufficient CSAPR allowances to cover affected facilities emission requirements through 2026, but may be required to purchase additional allowances in the future.

Regional Haze

The EPA issued final regulations for a Regional Haze Program in June 1999. The purpose of the regulations is to improve visibility in the form of reducing regional haze in 156 national parks and wilderness areas across the country. Haze is formed, in part, from emissions of SO_2 and NO_x. For phase one of the Regional Haze rule the Best Available Retrofit Technology ("BART") Report was submitted to the NDEE in August 2007 and a revised report was submitted in February 2008. The BART Report proposed that the Best Available Retrofit Technology to meet regional haze requirements at GGS would be low NO_x burners on Units No. 1 and No. 2 and no additional controls for SO_2. Low NO_x burners have now been installed on both units at GGS. The NDEE State Implementation Plan ("SIP") agreed with the BART Report. The NDEE submitted the SIP to the EPA for approval on June 30, 2011.

On May 30, 2012, the EPA issued a rule pertaining to the Regional Haze Program that would approve the trading program in CSAPR as an alternative to determining BART for power plants. As a result, states in the CSAPR region may substitute the trading program in CSAPR for source-specific BART for SO_2 and/or NO_x emissions as specified by CSAPR.

On July 6, 2012, the EPA issued the final rule on the Nebraska Regional Haze SIP. The final rule approved the GGS NO_x portion of the SIP but disapproved the SO_2 portion of the SIP for GGS. The EPA issued a Federal Implementation Plan ("FIP") for GGS which stated that BART for SO_2 control at GGS is in compliance with CSAPR. The District is currently in compliance with all requirements of phase one of the Regional Haze rule.

On January 10, 2017, the EPA issued final changes to the Regional Haze regulations for the second planning phase of the Regional Haze Rule. The District is evaluating the changes but will not know the full impact to the District until the State and the EPA begin implementing the second phase of the Regional Haze rule. The State is required to submit their SIP for the second phase of the Regional Haze rule by July 31, 2021.

On June 5, 2020, the District received an Information Collection Request ("ICR") from the NDEE for information pertaining to the second planning phase. Based on modeling performed by Central States Air Resources Agencies, the NDEE determined that GGS was contributing to the visibility impairment at multiple Class I areas. The NDEE ICR requested information regarding the cost to install and operate four SO_2 options at GGS Units No. 1 and No. 2. The District submitted the initial response to the NDEE ICR on November 2, 2020 and supplemental responses on December 30, 2020 and February 15, 2021. The District does not know if it will be required to install and operate any of the SO_2 control options. However, the District has indicated to the NDEE that if the District were to incur major emission control costs at GGS, it could affect the future economic viability of the station.

<u>Clean Power Plan</u>
On October 23, 2015, the EPA published the final Clean Power Plan ("CPP") rule addressing carbon dioxide reductions from existing fossil-fueled power plants. The final rule gave states significant responsibility for determining how to achieve the reduction targets through the development of a State Plan. Each state was given a reduction target to be achieved by 2030, with interim reductions required between 2022 and 2029. The Nebraska reduction target for 2030 was 40% below 2012 emissions. On February 9, 2016, the U.S. Supreme Court issued a stay for the CPP until all legal challenges have been decided. The D.C. Circuit Court of Appeals heard oral arguments on September 27, 2016. The D.C. Circuit Court continued to hold the case in abeyance until its dismissal on September 17, 2019.

On August 31, 2018, the EPA issued the proposed CPP replacement rule now called the Affordable Clean Energy ("ACE") rule. Under Section 111(d) of the Clean Air Act the EPA must determine the Best System of Emissions Reduction ("BSER") for CO_2 at individual fossil-fuel fired steam generating units. On June 19, 2019, the EPA issued the final ACE rule. The final ACE rule repealed the CPP and makes the determination that BSER for CO_2 at individual fossil-fuel fired steam generating units to be heat rate improvement projects. The EPA is also proposing to update the New Source Review process in a separate rulemaking. On September 17, 2019, the D.C. Circuit Court dismissed all legal challenges to the CPP as moot due to EPA repealing the CPP and replacing it with the ACE Rule.

On March 10, 2020, the District received an ICR from the NDEE for information pertaining to the ACE rule and a supplemental ICR received on May 8, 2020. The NDEE ICR requested information regarding the cost to install and operate the six Heat Rate Improvement ("HRI") technologies listed in the final ACE rule at GGS Units No. 1 and No. 2 and Sheldon Station Units No. 1 and No. 2. The ICR also requested information on setting a CO_2 emission rate standard in pounds CO_2/MWh. The District submitted the information to the NDEE by the September 11, 2020 due date. The District will not know the final impact of the ACE rule until the NDEE develops their State Plan.

It was announced on January 19, 2021 that the D.C. Circuit Court vacated the ACE rule. It is unknown what impact this action will have on the viability of the ACE rule and subsequent impacts on the development of the SIP.

<u>Endangered Species Act</u> –
The District applied to the U.S. Fish and Wildlife Service ("USFWS") under Section 10 of the Endangered Species Act ("ESA") for an Incidental Take Permit ("ITP") for the American burying beetle ("Beetle"), which is an endangered species. Issuance of an ITP is contingent upon USFWS acceptance of a Habitat Conservation Plan ("HCP") developed by the District to avoid, minimize and mitigate impacts on the Beetle. On February 8, 2019, the USFWS issued a Final Environmental Impact Statement ("FEIS") regarding the R-Project HCP to assess impacts on the environment. The FEIS describes the R-Project, certain alternatives, environmental impacts, cumulative impacts, comparison of alternatives and compliance and other environmental laws. On June 12, 2019, the USFWS issued its Record of Decision and the ITP. An escrow agreement was executed with USFWS to serve as financial assurance for the District's restoration obligations with respect to the R-Project.

On July 5, 2019, two nonprofit organizations and two other petitioners ("Petitioners") filed a petition for review in Colorado federal district court against three USFWS and Department of the Interior officials. The lawsuit challenged the ITP that the USFWS issued to the District for incidental take of the beetle from the construction, operation, and maintenance of the R-Project, alleging claims under the ESA, National Environmental Policy Act, and National Historic Preservation Act. The District intervened in the lawsuit to defend the ITP issuance and USFWS decisions.

On June 17, 2020, the district court issued its decision, finding in favor of the USFWS and the District on several counts, while also identifying certain discrete errors in the agency's decision-making process and finding for Petitioners on certain narrow grounds. The court on that basis vacated and remanded the ITP to the USFWS. Following the court's decision, and in compliance therewith, the District halted all construction on the R-Project, which construction had commenced in accordance with a stipulation between the parties to the litigation. The District, with notice to USFWS, is taking steps within the R-Project area to stabilize sites disturbed by those construction activities, protect the integrity of equipment and other project materials, and to remove debris and other potential hazards from landowners' property. The District is presently undertaking those measures while the R-Project construction is paused following, and consistent with, the district court's decision.

The District and USFWS both decided not to appeal the district court's decision. The District is communicating with USFWS to address future ESA compliance issues for the R-Project in light of the district court's decision. Because the U.S. Army Corps of Engineers' ("Corps'") verification of the R-Project's use of Clean Water Act 404 Nationwide Permit 12 (the "404 Permit") relied on the USFWS's findings for the R-Project, the Corps suspended that permit on September 17, 2020. The District anticipates recommencing construction activities for the R-Project once the ESA compliance approach, and any other permit or agency authorization required for the ESA compliance approach for the R-Project, has been completed.

<u>Impact from Changes to Environmental Regulatory Requirements</u> –
Any changes in the environmental regulatory requirements imposed by federal or state law which are applicable to the District's generating stations could result in increased capital and operating costs being incurred by the District. The District is unable to predict whether any changes will be made to current environmental regulatory requirements, if such changes will be applicable to the District and the costs thereof to the District.

G. *Impact on Operations and Damages from Adverse Weather Conditions and Sale of Water Rights*
In mid-March 2019, multiple river basins in northern and eastern Nebraska, as well as river basins in the surrounding region, experienced unprecedented weather conditions as a result of exiting snowpack, blizzard conditions, frozen ground, significant rainfall and ice conditions on and around numerous rivers and their tributaries. The District sustained significant damage at the Spencer Hydro Facility, a small hydro plant on the Niobrara River in northern Nebraska accredited at 1.28 MW, which produced 10,509 MWh in 2018. The Spencer Hydro Facility, including the hydro plant and the concrete and earthen dam structures (collectively, the "Spencer Hydro Facility"), was damaged. An individual living below the dam has been missing and declared dead. The District also experienced damages to transmission and substation facilities. Certain distribution facilities were also damaged, and a small number of customers lost service for an extended period due to protracted flood conditions in low-lying areas. CNS declared a Notice of Unusual Event ("NOUE") for several days due to flooding conditions along the Missouri River, but operated continuously during the period. Restoration costs for all facilities, except the Spencer Hydro Facility, through December 31, 2020, were $10.1 million. The estimated cost to decommission the Spencer Hydro Facility is $9.4 million. As of December 31, 2020, $1.3 million had been incurred for preliminary damage assessments by District employees and external consultants, and for site safety and security of the Spencer Hydro Facility.

The District has been working with the Federal Emergency Management Agency ("FEMA") to make appropriate claims for reimbursement for a portion of the storm-related costs. The District estimates that approximately 60-70 percent of the costs from the March 2019 weather events may be reimbursed by FEMA. FEMA is requiring a detailed study on the cost of rebuilding and the cost of removing the Spencer Hydro Facility, which the District is pursuing through an engineering firm. The District expects to eventually remove the Spencer Hydro Facility which will require approval from the Nebraska Department of Natural Resources (the "NDNR"), which regulates the Spencer Hydro Facility, with input from other state and federal agencies.

The NDNR requested an independent investigation of the events at the Spencer Hydro Facility through the Association of State Dam Safety Officials (the "ASDSO"). The ASDSO issued its report in April 2020 and found that the flood of water and ice greatly exceeded the capacity of the dam and its spillways and that there was nothing the dam operators could have done to prevent the dam from failing. However, the ASDSO identified two key human factors contributing to the dam failures and consequences. First, there is a lack of industry knowledge about ice run dam storm damage and the NDNR did not know that the Spencer Hydro Facility had failed in 1960 and 1966, and the District had limited knowledge of such prior failures. Second, the NDNR and the District, based on the dam's hazard classification, underestimated the potential of the dam to cause life-threatening flooding in the event of a dam failure. The District is continuing to study the report and disputes certain findings in the report.

Prior to this incident, a contract was signed for the sale of the District's Spencer Hydro Facility, including dam, structures, land, water appropriations, and perpetual easements for the reservoir, to the Niobrara River Basin Alliance (Five Natural Resource Districts) and the Nebraska Game and Parks Commission. Due to the damages sustained to the facility and related structures, the contract for sale has been amended by the parties to provide for only the sale of the water rights associated with the Spencer Hydro Facility.

The District has been sued in a tort action in state court by the estate and family of the individual declared deceased following the events at the Spencer Hydro Facility for loss of life and property damage. Plaintiffs allege that their damages in the tort action exceed \$5.0 million. The case is currently in the discovery process. The District has also been sued in state court for alleged inverse condemnation of property located further downstream. The inverse condemnation action claims damages of approximately \$3.0 million. The case is also in early stages of discovery. At this time, it is not possible to predict the outcome of such lawsuits or any other claims that may arise. It is possible that the cost of such lawsuits or potential other claims could be significant, although tort liability for the District is capped under Nebraska statute to no more than \$5.0 million for all claims arising out of a single occurrence. The cost of removing the Spencer Hydro Facility also could be significant. The District maintains property and liability insurance and has notified its carriers of the events at the Spencer Hydro Facility.

13. LITIGATION:

In 2017, the Nebraska Department of Revenue ("NDOR") conducted a sales and use tax audit on the District's records for the audit period of June 1, 2014 through May 31, 2017. NDOR issued a Notice of Deficiency Determination ("Determination") to the District for approximately \$6.5 million, including interest and penalties of over \$1.0 million, on January 30, 2018. Beyond the minor sales and use tax corrections contained in a normal audit Determination, the NDOR assessed almost \$5.5 million of tax on the payments to municipalities under PRO Agreements. The District disagreed with the NDOR's assessment and filed a Petition for Redetermination to formally challenge the Determination on March 29, 2018. State legislation was passed in 2019 that exempted these payments from sales and use tax, but the Petition for Redetermination for the years prior to 2019 has not yet been addressed by NDOR.

Information on litigation related to the R-Project and the USFWS is included in Note 12.F.

Information on litigation related to the adverse weather conditions in March 2019 is included in Note 12.G.

A number of claims and suits are pending against the District for alleged damages to persons and property and for other alleged liabilities arising out of matters usually incidental to the operation of a utility, such as the District. In the opinion of management, based upon the advice of its General Counsel, the aggregate amounts recoverable from the District, considering estimated amounts provided in the financial statements and insurance coverage, are not material.

14. SUBSEQUENT EVENTS:

February 2021 Extreme Weather Event
There was an extreme weather event in February 2021 that impacted several states, including the area served by SPP as well as neighboring regional transmission organizations. The record low temperatures, combined with a shortage of natural gas, limitations and forced outages to traditional energy resources, and low availability of renewable generation, resulted in electricity usage that exceeded available generation across the SPP service territory at different periods of time on February 15 and 16. The District is required to purchase energy from SPP to serve its firm load and is also required to dispatch its generation and sell energy into the SPP market based on direction from SPP. For approximately two weeks in the middle of February, the District was in a position to generate more electricity to support the grid during these times of higher loads and market prices. The District had sufficient inventories of coal during this event, but natural gas purchases were required for certain generating units. Although

the prices paid for natural gas during this time period were very high, the prices paid to the District for the power it was generating into SPP were also high and covered the high natural gas costs. The diversity and availability of the District's entire fleet of generation resources helped support the region's overall power needs and helped prevent an adverse financial impact to the District's customers during this unprecedented weather event. The net SPP settlements for the District, after reductions for financial hedges, payments to participants and estimated additional charges from SPP resettlements, were favorable by $139.6 million for February 2021. This amount does not include deductions for the related variable costs for fuel and other operating expenses. Most of the variable costs incurred were for natural gas. Natural gas purchases were $45.4 million for February 2021.

Subsequent Debt Activity

In March 2021, the District initiated the preliminary closing on $127.6 million of General Revenue Bonds, 2021 Series A and 2021 Series B, which was a Forward Delivery transaction with a settlement date of October 2021. Additional details are included in Note 7.

SUPPLEMENTAL SCHEDULES (UNAUDITED)

Calculation of Debt Service Ratios in accordance with the General Revenue Bond Resolution for the years ended December 31, (in 000's)	2020	2019
Operating revenues	$ 1,103,149	$ 1,074,475
Operating expenses	(1,011,837)	(974,102)
Operating income	91,312	100,373
Investment and other income	51,629	47,050
Debt and related expenses	(47,049)	(58,239)
Increase in net position	95,892	89,184
Add:		
Debt and related expenses[1]	47,049	58,239
Depreciation and amortization[2]	126,215	124,972
Payments to retail communities[3]	28,252	27,983
Amortization of current portion of financed nuclear fuel[4]	32,622	38,959
Amounts collected from third party financing arrangements[5]	541	1,036
	234,679	251,189
Deduct:		
Investment income retained in construction funds[6]	341	603
Unrealized gain on investment securities	460	4,048
	801	4,651
Net revenues available for debt service under the General System Bond Resolution	$ 329,770	$ 335,722
General system bonded debt service[7]	174,606	153,995
Ratio of net revenues available for debt service[7]	1.89	2.18

(1) Debt and related expenses, exclusive of interest on customer deposits, is not an operating expense as defined in the General Resolution.
(2) Depreciation and amortization are not operating expenses as defined in the General Resolution.
(3) Under the provisions of the General Resolution, the payments required to be made by the District with respect to the Professional Retail Operating Agreements are to be made on the same basis as subordinated debt.
(4) General Revenue Bond financed nuclear fuel is not an operating expense as defined in the General Resolution. Amortization of nuclear fuel expense under the Taxable Revolving Credit Agreement is excluded from the debt service calculation as the District's obligation to make payments under the Taxable Revolving Credit Agreement is subordinate to the District's obligation to pay debt service on General Revenue Bonds.
(5) The payments received by the District from third party financing arrangements are included as Revenues under the General Resolution but are not recognized as revenue under GAAP.
(6) Interest income on investments held in construction funds is not Revenue as defined in the General Resolution.
(7) Debt Service was higher and the Ratio of Net Revenues Available for Debt Service was lower for the year ended December 31, 2020, than for the year ended December 31, 2019, due primarily to the inclusion of the Debt Service on the General Revenue Bonds, 2010 Series C, redeemed in December 2020. The District prefers to show all Debt Service paid from Revenues, including Debt Service on redeemed Bonds, even though the General Resolution defines Debt Service only to include scheduled Debt Service. If the Debt Service on the said General Revenue Bonds so redeemed were excluded for the year ended December 31, 2020, the Debt Service and the Ratio of Net Revenues Available for Debt Service for such period would be $139,466 and 2.36 times, respectively.

Schedule of Changes in the Net OPEB Liability and Related Ratios using a January 1 Measurement Date (in 000's)

Total OPEB Liability	2020	2019	2018	2017	2016
Service Cost	$ 2,299	$ 2,771	$ 2,760	$ 3,322	$ 3,229
Interest	19,604	19,661	20,032	20,658	19,876
Differences between Expected and Actual Experiences	(19,961)	(8,686)	(19,570)	(203)	13,657
Changes of Assumptions	(1,607)	(751)	5,585	(18,807)	(9,149)
Benefit Payments, net of employee contributions	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Net Change in Total OPEB Liability	(12,472)	(1,065)	(6,607)	(8,489)	10,711
Total OPEB Liability (Beginning)	317,672	318,737	325,344	333,833	323,122
Total OPEB Liability (Ending) (a)	$ 305,200	$ 317,672	$ 318,737	$ 325,344	$ 333,833
Plan Fiduciary Net Position					
Contributions	$ 41,084	$ 56,706	$ 28,439	$ 74,711	$ 28,242
Net Investment Income (Loss)	41,733	(6,892)	21,350	6,102	(453)
Benefit Payments, net of employee contributions	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Administrative Expense	(188)	(130)	(70)	(69)	(150)
Net Change in Plan Fiduciary Net Position	69,822	35,624	34,305	67,285	10,737
Plan Fiduciary Net Position (Beginning)	212,438	176,814	142,509	75,224	64,487
Plan Fiduciary Net Position (Ending) (b)	$ 282,260	$ 212,438	$ 176,814	$ 142,509	$ 75,224
Net OPEB Liability (Ending) (a) - (b)	$ 22,940	$ 105,234	$ 141,923	$ 182,835	$ 258,609
Net Position as a % of Total OPEB Liability	92.5%	66.9%	55.5%	43.8%	22.5%

GASB Statement No. 75, Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans, was implemented by the District in 2016. The provisions of this Statement were not applied to prior periods, as it was not practical to do so as the information was not readily available. The OPEB schedules are intended to show information for ten years. Additional years will be displayed when available.

Schedule of OPEB Contributions for Years Ended December 31, (in 000's)

	2020	2019	2018	2017	2016
Actuarially Determined Contribution	$ 6,676	$ 12,967	$ 18,572	$ 21,006	$ 28,283
Contributions Made in Relation to the Actuarially Determined Contribution	28,283	41,084	56,706	28,439	74,712
Contribution Deficiency (Excess)	$ (21,607)	$ (28,117)	$ (38,134)	$ (7,433)	$(46,429)

Notes to Schedule:

Valuation date – Actuarially determined contribution rates are calculated as of January 1, one year prior to the end of the fiscal year in which contributions are reported.

Methods and assumptions used for 2020 –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	13-year closed period
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 7.1% initial, ultimate 4.5% Post-Medicare: 7.8% initial, ultimate 4.5%
Administrative cost trend	3.0%
Inflation	2.2%
Salary increases	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Discount rate	6.25%, based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	Pub-2010 "General" table with generational projection using Scale MP-2019
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 60% of females are assumed to have spouses who will elect coverage. Males are assumed to be two years older than their spouses. Females are assumed to be two years younger.
Participation rate	95.0%

Methods and assumptions used for 2019 –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	14-year closed period
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 7.4% initial, ultimate 4.5% Post-Medicare: 8.2% initial, ultimate 4.5% Included impact of the excise tax (not repealed until 12/2019)
Administrative cost trend	3.0%
Inflation	2.3%
Salary increases	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Discount rate	6.25%, based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	Pub-2010 "General" table with generational projection using Scale MP-2018
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 60% of females are assumed to have spouses who will elect coverage. Males are assumed to be two years older than their spouses. Females are assumed to be two years younger.
Participation rate	95.0%

Methods and assumptions used for 2018 –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	15-year closed period
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 7.7% initial, ultimate 4.5% Post-Medicare: 8.7% initial, ultimate 4.5%
Administrative cost trend	3.0%
Inflation	2.3%
Salary increases	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Discount rate	6.25%, based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2017 with generational projection
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 30% of females are assumed to have spouses who will elect coverage. Males are assumed to be three years older than their spouses. Females are assumed to be three years younger.
Participation rate	100.0%

Methods and assumptions used for 2017 –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	16-year closed period
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 7.3% initial, ultimate 4.5% Post-Medicare: 9.1% initial, ultimate 4.5%
Administrative cost trend	3.0%
Inflation	2.1%
Salary increases	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Discount rate	6.25%, based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2016 with generational projection
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 30% of females are assumed to have spouses who will elect coverage. Males are assumed to be three years older than their spouses. Females are assumed to be three years younger.
Participation rate	100.0%

Methods and assumptions used for 2016 –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	17-year closed period
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 8% initial, ultimate 5% Post-Medicare: 6.75% initial, ultimate 5%
Administrative cost trend	3.0%
Inflation	2.1%
Salary increases	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Discount rate	6.25%, based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2015 with generational projection
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 30% of females are assumed to have spouses who will elect coverage. Males are assumed to be three years older than their spouses. Females are assumed to be three years younger.
Participation rate	100.0%

Schedule of Investment Returns for Years Ended December 31,

	2020	2019	2018	2017	2016
Annual Money-Weighted Rate of Return, Net of Investment Expense	15.6%	18.9%	(3.6)%	14.2%	5.8%

GASB Statement No. 75, Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans, was implemented by the District in 2016. The provisions of this Statement were not applied to prior periods, as it was not practical to do so as the information was not readily available. The OPEB schedules are intended to show information for ten years. Additional years will be displayed when available.

www.nppd.com

PO Box 499 1414 15th Street Columbus, NE 68602-0499
1-877-275-6773