
2021 Financial Report
Together, we are
Powering Our Future
Nebraska Public Power District
Always there when you need us

Vision

We are a premier energy provider bringing the best of public power to Nebraskans, powering everyday life and a brighter future.

Mission

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

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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 5,366 miles of transmission and subtransmission lines and 2,814 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 an average of nearly 93,000 residential, commercial and industrial customers in 79 Nebraska communities at retail.

Formed by a merger on Jan. 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.

Control 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. (1)

BY THE NUMBERS

31 GENERATING FACILITIES

5,366 MILES TRANSMISSION & SUBTRANSMISSION LINES

2,814 MILES DISTRIBUTION LINES

46 MUNICIPALITIES SERVED AT WHOLESALE

79 COMMUNITIES SERVED BY RETAIL

24 PUBLIC POWER DISTRICTS SERVED AT WHOLESALE

1,900+ TEAMMATES WORKING FOR YOU

$1.2 Billion OPERATING REVENUE

600,000 NEBRASKANS SERVED IN PARTNERSHIP WITH OTHER UTILITIES

3,230 MW DIVERSE GENERATION

93,000 RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS

86 of 93 (1) NEBRASKA COUNTIES ARE SERVED BY NPPD

(1) On Feb. 18, 2022, the Nebraska Power Review Board approved an amendment to NPPD's chartered territory to better align with the retail and wholesale service areas and voting subdivision boundaries based on the 2020 Census. With the amendment, the District's chartered territory includes all or parts of 84 of the State's 93 counties.

BOARD OF DIRECTORS

Mary A. Harding
Plattsmouth
Subdivision 1

Aaron D. Troester
O'Neill
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

Wayne E. Williams
Central City
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

SENIOR MANAGEMENT TEAM

Thomas J. Kent
President & Chief Executive Officer

Timothy J. Arlt
Vice President, Corporate Strategy & Innovation

Traci L. Bender (1)
Executive Vice President, Chief Financial Officer & Treasurer

Dallas M. Beshaler
Vice President, Human Resources & Corporate Services

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

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

Laura L. Kapustka (1)
Vice President, Chief Financial Officer & Treasurer

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

Michael J. Spencer
Vice President, Energy Production

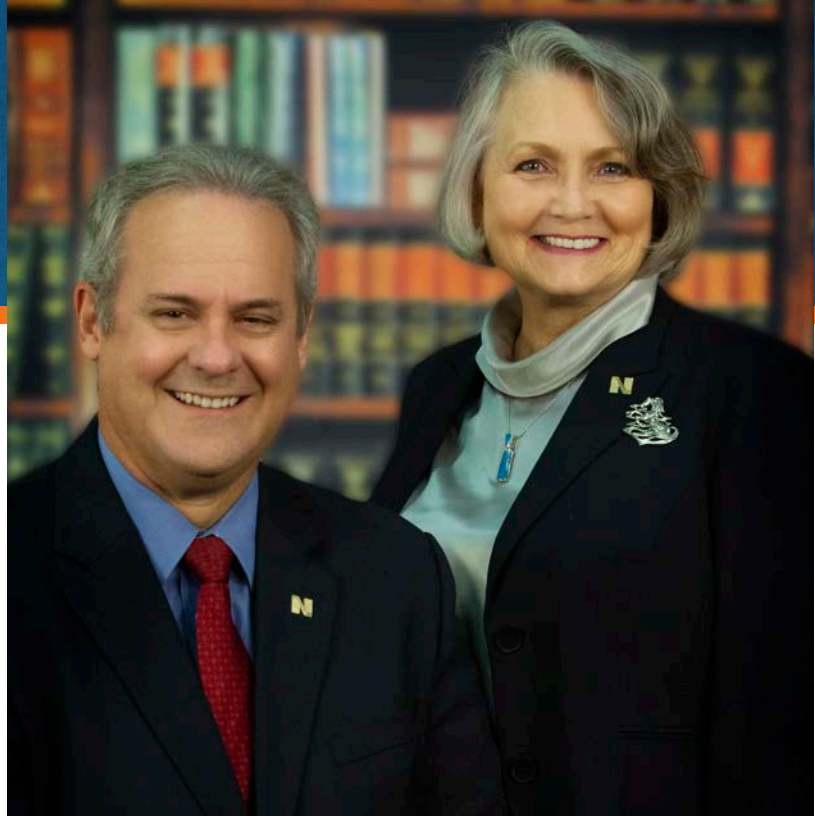
Robyn A. Tweedy
Vice President, Enterprise Technology & Chief Information Officer

Arthur R. Wiese
Vice President, Energy Delivery

(1) Traci Bender served as Executive Vice President, Chief Financial Officer & Treasurer until her replacement by Laura Kapustka on April 16, 2021.

A Message

FROM OUR 2021 BOARD CHAIR and CHIEF EXECUTIVE OFFICER



Thomas J. Kent
President & CEO

Mary A. Harding
2021 Board Chair

As we reflect on 2021, we can appreciate the challenges and accomplishments both our organization and our customers experienced, which included working and living through a second year of an ongoing pandemic. NPPD was able to meet these challenges and maintain a high level of performance throughout the organization benefiting our customers.

One challenge came in February, when the entire Central U.S. faced widespread extreme cold weather that lasted multiple days, impacting communities throughout the Southwest Power Pool (SPP). SPP is a Regional Transmission Organization that oversees the bulk electric grid and wholesale power market in all or parts of 14 states from the panhandle of Texas up through North Dakota. SPP is tasked with ensuring reliable supply of power, adequate transmission infrastructure, and competitive wholesale energy prices throughout the footprint. NPPD is a member of SPP, and during this extreme weather event the demand for electricity, across the entire region, hit a point where it was higher than the amount of electricity available. The causes for the limited power supply included natural gas and other fuel-supply issues, equipment malfunctions and transmission system constraints. This resulted in rolling regional interruptions of service to some customers for 30-60 minutes which covered approximately four hours total over a two-day period. While it was very unfortunate these outages had to occur, these actions, which were required by national reliability standards and federal regulations, protected the system from being damaged and prevented uncontrolled and widely spread outages that could have lasted days.

As we look back at NPPD's performance during this event, we were able to keep all our plants running to supply power not only to our customers, but to others within SPP.

This is thanks to the hard work of teammates. Our team's focus on operational excellence year-round is what ensured our plants and transmission and distribution facilities performed when they were needed the most.

The financial performance in February was a big part of an overall excellent financial year for NPPD (detailed in this report). Selling our extra generation into the market during the February cold weather event was a major contributor to our year-end surplus of $144.6 million. We head into 2022 with no overall rate increase for our retail customers for the ninth straight year and likewise for our wholesale customers for the fifth straight year. In addition, the board approved a financial credit for our wholesale customers for the fourth straight year. This is a big accomplishment and a reflection of the hard work by NPPD staff to ensure we can generate and deliver reliable, low cost, and sustainable energy to our customers.

This year also provided the opportunity for our customers, board members and management team to work closely together as we developed a goal to achieve net-zero carbon emissions from generation resources by 2050. This was not a short process and in addition to the continued conversations with customers, establishing this goal took several years of studying the risks and trends that impact our industry. It was clear our customers wanted to keep a strong focus on reliability and affordable rates, and the goal approved by the board maintains that focus while looking at future actions to achieve net-zero carbon emissions from generation resources. The process is not one that can happen overnight and will likely require the implementation of technologies that are not yet commercially available. NPPD is in a great position to address the changes we may face moving into the future, thanks to our diverse generation mix which has served our customers well. Maintaining that diversity will be an important focus as we look at any changes we might make to that mix in the future.

As Nebraskans, we are accustomed to working together and helping our neighbors when they need a hand. That was on full display in 2021, and it will certainly not be the last time we are faced with difficult situations. As we reflect on the year that was and turn our focus toward the future, NPPD remains committed to our vision of being a premier energy provider, that brings the best of public power to Nebraskans, powering everyday life and a brighter future.

2021

FINANCIAL REPORT

NEBRASKA PUBLIC POWER DISTRICT

YEAR AT A GLANCE

KILOWATT - HOUR SALES		19.4	BILLION
OPERATING REVENUES	$	1,221.8	MILLION
COST OF POWER PURCHASED AND GENERATED	$	648.7	MILLION
OTHER OPERATING EXPENSES	$	415.6	MILLION
INVESTMENT AND OTHER INCOME	$	14.6	MILLION
DEBT AND RELATED EXPENSES	$	39.0	MILLION
INCREASE IN NET POSITION	$	133.1	MILLION
DEBT SERVICE COVERAGE		2.71	TIMES

2021 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	10.37 ¢	12.42 ¢	73,364	848,568	4.4	$ 105,431	8.6
Commercial	8.12 ¢	9.57 ¢	19,524	1,094,030	5.6	104,685	8.6
Industrial	4.03 ¢	4.38 ¢	60	1,886,247	9.7	82,638	6.8
Total Retail Sales	6.61 ¢	7.65 ¢	92,948	3,828,845	19.7	292,754	24.0
Wholesale:							
Municipalities[2]		5.62 ¢	38	1,326,261	6.9	74,582	6.1
Municipalities (Partial Requirements)[3]		4.81 ¢	8	53,204	0.3	2,559	0.2
Public Power Districts and Cooperatives[2]		5.23 ¢	23	7,883,465	40.6	412,562	33.8
Public Power Districts (Partial Requirements)[3]		4.37 ¢	1	27,849	0.1	1,218	0.1
Total Firm Wholesale Sales		5.28 ¢	70	9,290,779	47.9	490,921	40.2
Total Firm Retail and Wholesale Sales		5.97 ¢	93,018	13,119,624	67.6	783,675	64.2
Participation Sales		4.31 ¢	4	1,547,836	8.0	66,702	5.5
Other Sales[4]		8.15 ¢	1	4,746,375	24.4	386,641	31.6
Total Electric Energy Sales		6.37 ¢	93,023	19,413,835	100.0	1,237,018	101.3
Other Operating Revenues[5]						72,267	5.9
Unearned Revenues[6]						(87,507)	(7.2)
Total Operating Revenues						$1,221,778	100.0

COST OF POWER PURCHASED AND GENERATED	MWh Amount	MWh %	Costs (in 000's) Amount	Costs (in 000's) %
Production[7]	15,449,381	76.7	$ 428,789	66.1
Power Purchased	4,680,183	23.3	219,941	33.9
Total Production and Power Purchased	20,129,564	100.0	$ 648,730	100.0

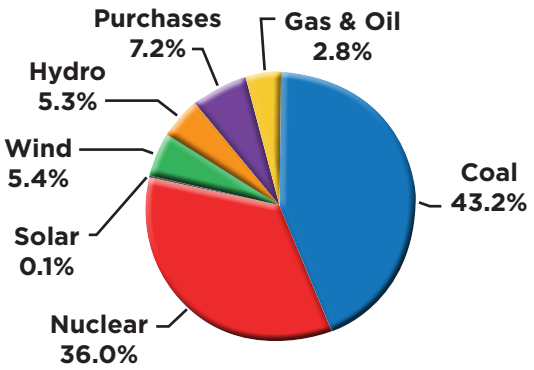
CONTRACTUAL AND TAX PAYMENTS (in 000's) [1]	Amount
Payments to Retail Communities	$ 30,119
Payments in Lieu of Taxes	9,906
Total Contractual and Tax Payments	$ 40,025

OTHER	Amount
Miles of Transmission and Subtransmission Lines in Service	5,366
Number of Full-Time Employees	1,928

(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 Required Supplementary Information. The Financial Statements consist of the Statements of Net Position, the Statements of Revenues, Expenses, and Changes in Net Position, the Statements of Cash Flows, the Statements of Fiduciary Net Position, and the Statements of Changes in Fiduciary Net Position.

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, Notes to Financial Statements and Required Supplementary Information.

The Statements of Net Position present assets, deferred outflows of resources, liabilities, deferred inflows of resources and net position as of December 31, 2021 and 2020. The Statements of Revenues, Expenses, and Changes in Net Position present the operating results for the years 2021 and 2020. The Statements of Cash Flows present the sources and uses of cash and cash equivalents for the years 2021 and 2020. The Statements of Fiduciary Net Position present the financial resources available for other postemployment benefits as of December 31, 2021 and 2020. The Statements of Changes in Fiduciary Net Position present the additions, deductions and changes in net position restricted for other postemployment benefits as of December 31, 2021 and 2020. 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, 2021 and 2020, and the results of operations for the years 2021 and 2020. The Required Supplementary Information 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 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.

On February 18, 2022, the Nebraska Power Review Board approved an amendment to the District's chartered territory to better align with the retail and wholesale service areas and voting subdivision boundaries based on the 2020 Census. With the amendment, the District's chartered territory includes all or parts of 84 of the State's 93 counties. Prior to the amendment, the District's chartered territory included all or parts of 86 of the State's 93 counties. The reduction in counties primarily resulted from the removal of the wholesale customers who did not sign the District's 2016 wholesale power contracts (the "2016 Contracts") which replaced the 2002 wholesale power contracts (the "2002 Contracts"). Those customers who remained on the 2002 Contracts phased out their power supply from the District at the end of 2021.

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 1,928 full-time employees as of December 31, 2021. 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 peak load in 2021 of 2,904.4 megawatts ("MW"), the District had available 3,617.8 MW of capacity resources that included 3,011.9 MW of generation capacity from 11 owned and operated generating plants and 20 plants over which the District has operating control, 442.3 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 of 3,617.8 MW, 386.9 MW are being sold via participation sales or other capacity sales agreements, leaving 3,230.9 MW to serve the District's firm retail and wholesale customers and to meet capacity reserve requirements. The highest summer peak load of 3,030.3 MW was established in July 2012 and the highest winter 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 2021 accredited capacity.

	CAPACITY RESOURCES		
Type	Number of Plants[1]	Summer 2021 Accredited Capacity (MW)[2]	Percent of Total
Steam - Conventional[3]	3	1,683.3	55.9
Steam - Nuclear	1	770.0	25.6
Hydro	5	113.7	3.8
Diesel	10	70.7	2.3
Combustion Turbine[4]	3	123.1	4.1
Combined Cycle	1	220.0	7.3
Wind[5]	8	31.1	1.0
	31	3,011.9	100.0

(1) Includes three hydro plants and ten diesel plants under contract to the District.
(2) Accreditation by SPP for the summer season 2021, pursuant to standard performance tests conducted by the District. Pursuant to agreements with other utilities, a portion of the accredited capacity of certain generating plants has been sold to such utilities.
(3) Includes Gerald Gentleman Station, Sheldon Station and Canaday Station.
(4) Includes the Hallam, Hebron and McCook peaking turbines.
(5) Includes Ainsworth Wind Energy Facility and seven wind facilities under contract to the District.

In 2021, the Board approved a goal to achieve net zero carbon emissions from generation resources by 2050. The District worked with its wholesale customers and the communities it serves to develop a policy to enable this goal, while maintaining affordability, reliability and system resiliency.

The District continues to collaborate with communities for solar projects, including a project in Ainsworth which was completed in 2021. Solar projects which are underway and scheduled for completion in 2022 include Ogallala, Norfolk and York. The Norfolk project will also have a pilot utility scale of 1 MW for battery storage.

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 2017 through 2021.

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

Year	Coal[1]	Nuclear	Hydro[2]	Wind[3]	Gas and Oil	Purchases[4]	Solar[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
2021	43.2	36.0	5.3	5.4	2.8	7.2	0.1

(1) Includes NC2.
(2) Includes hydro purchases from Loup River Public Power District ("Loup"), over which the District has operating control, and Western.
(3) Includes Ainsworth Wind Energy Facility, 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 Gerald Gentleman Station.
(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 2021 accredited capacity and in-service dates.

DISTRICT-OWNED GENERATION FACILITIES

Facility	Fuel Type	Summer 2021 Accredited Capacity (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	123.1	1973
Canaday Station	Natural Gas	99.3	1958
Hydro (2 generating plants)	Water	24.0	1887, 1939
Ainsworth Wind Energy Facility[2]	Wind	4.3	2005
		2,824.7	

(1) 2021 summer accredited net capacity based on SPP criteria.
(2) Nominally rated at 60 MW.

THE CUSTOMERS

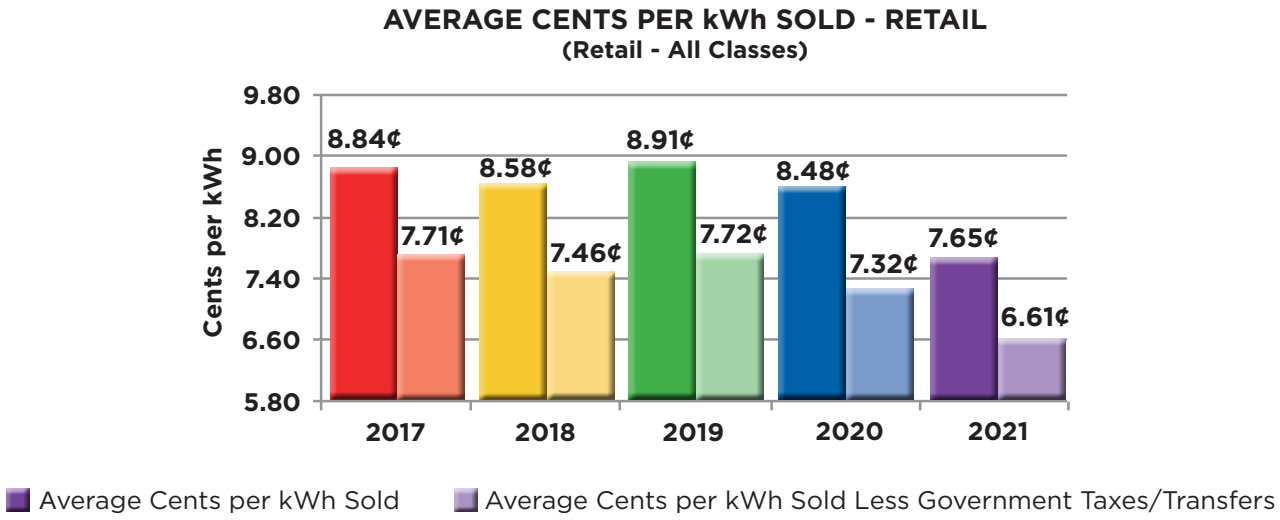
Retail and Wholesale Customers

In 2021, the District served an average of 92,948 retail customers. The District's retail service territory includes 77 municipal-owned distribution systems operated by the District within the state of Nebraska for the municipality pursuant to a Professional Retail Operations Agreement ("PRO Agreement") and two retail communities in South Dakota. Details of the District's PRO Agreements are included in Note 12.C., *Retail Agreements and Wholesale Power Contracts,* in the Notes to Financial Statements.

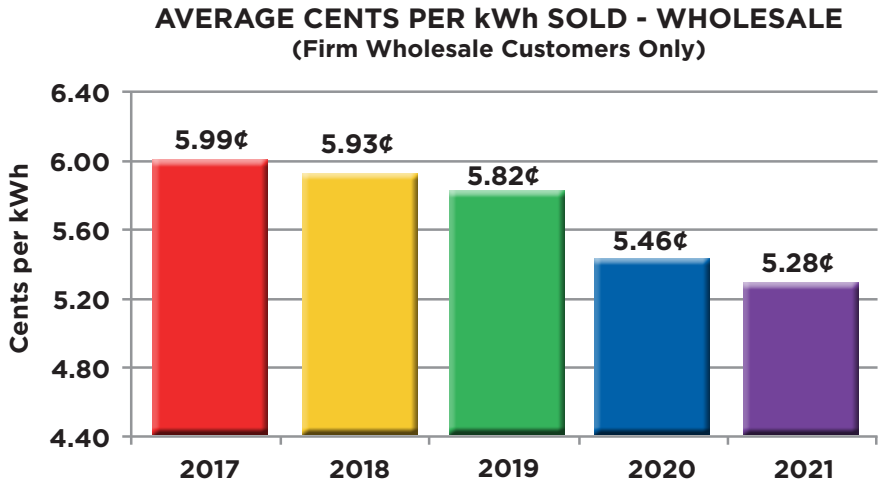
The District serves its wholesale customers under total and partial requirements contracts that require them to purchase total power and energy requirements from the District, subject to certain exceptions. In 2016, the District entered into 20-year 2016 Contracts with a substantial number of its existing wholesale customers. Wholesale customers being 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 2002 Contracts expired on December 31, 2021.

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 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 23.2% for 2020, based on the latest available data. Details of the District's Wholesale Power Contracts are included in Note 12.C., *Retail Agreements and Wholesale Power Contracts,* in the Notes to Financial Statements.

The following chart shows the District's average retail cents per kWh for the years ended December 31, 2017 through 2021. 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 2021 from 2020 was due to a 41.3% increase in industrial energy sales, which has the lowest rates of all the retail customer classes.



The following chart shows the District's average wholesale cents per kWh for the years ended December 31, 2017 through 2021. The decrease in the average cents per kWh sold in 2021 from 2020 was due to a 1.2% increase in energy sales and a higher Production Cost Adjustment ("PCA") refund.



Participation Sales and Other Sales

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 Wind Energy Facility from October 1, 2005 through December 31, 2019.

Transmission Customers

The District owns and operates 5,366 miles of transmission and subtransmission lines, encompassing nearly the entire State of Nebraska. 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.

Customers, Energy Sales, and Revenues

The following table shows customers, energy sales and peak loads of the System, including participation sales, in each of the three years, 2019 through 2021.

			Megawatt-Hour Sales				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
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
2021	92,948	75	13,119,624	5.4	19,413,835	2.7	2,904.4

(1) For 2021, 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 retail and 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. The increase in native load sales from 2020 to 2021 was due primarily to an increase of 41.3% in retail industrial energy sales and a 1.2% increase in wholesale energy sales. The increase from 2019 to 2020 was due primarily to more cooling degree days in 2020 as compared to 2019, due to the hotter, drier summer.

(3) Total sales from the System include sales to Lincoln from Gerald Gentleman Station; to MEAN, OPPD and Grand Island from Ainsworth Wind Energy Facility, 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 Gerald Gentleman Station and Cooper Nuclear Station, 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) See (2) for explanations for the change in native load sales. The increase in percentage growth for total sales from 2020 to 2021 was due to the additional native load sales. There was a 2.2% decrease in off-system or nonfirm sales from 2020 to 2021. 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 Cooper Nuclear Station planned refueling and maintenance outage, other fossil station outages and reduced generation due to lower market prices in the SPP Integrated Market.

FINANCIAL INFORMATION

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

CONDENSED STATEMENTS OF NET POSITION (in 000's)

As of December 31,	2021	2020	2019
Current Assets	$ 1,027,068	$ 884,104	$ 990,989
Special Purpose Funds	788,842	824,572	770,592
Utility Plant, Net	2,518,593	2,571,381	2,532,806
Other Long-Term Assets	276,219	275,517	312,163
Deferred Outflows of Resources	149,550	101,751	294,168
Total Assets and Deferred Outflows	$ 4,760,272	$ 4,657,325	$ 4,900,718
Current Liabilities	$ 180,338	$ 309,371	$ 293,862
Long-Term Debt	1,283,134	1,345,408	1,482,409
Other Long-Term Liabilities	828,362	792,188	981,074
Deferred Inflows of Resources:			
Unearned Revenues	268,096	201,589	262,500
Other Deferred Inflows	313,062	254,552	222,548
Net Position	1,887,280	1,754,217	1,658,325
Total Liabilities, Deferred Inflows, and Net Position	$ 4,760,272	$ 4,657,325	$ 4,900,718

CONDENSED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION (in 000's)

For the years ended December 31,	2021	2020	2019
Operating Revenues	$ 1,221,778	$ 1,103,149	$ 1,074,475
Operating Expenses	(1,064,354)	(1,011,837)	(974,102)
Operating Income	157,424	91,312	100,373
Investment and Other Income	14,608	51,629	47,050
Debt and Related Expenses	(38,969)	(47,049)	(58,239)
Increase in Net Position	$ 133,063	$ 95,892	$ 89,184

SOURCES OF OPERATING REVENUES (in 000's)

For the years ended December 31,	2021	2020	2019
Firm Retail and Wholesale Sales	$ 783,675	$ 778,435	$ 807,201
Participation Sales	66,702	64,731	59,717
Other Sales	386,641	106,312	165,613
Other Operating Revenues	72,267	71,760	77,591
Unearned Revenues	(87,507)	81,911	(35,647)
Total Operating Revenues	$ 1,221,778	$ 1,103,149	$ 1,074,475

CONDENSED STATEMENTS OF CASH FLOWS (in 000's)

For the years ended December 31,	2021	2020	2019
Net Cash Provided by Operating Activities	$ 419,907	$ 205,431	$ 358,025
Net Cash Provided by (Used in) Investing Activities	(94,413)	128,242	(58,362)
Net Cash Used in Capital and Financing Activities	(314,472)	(326,151)	(308,920)
Net Increase (Decrease) in Cash and Cash Equivalents	11,022	7,522	(9,257)
Cash and Cash Equivalents, Beginning of Year	23,767	16,245	25,502
Cash and Cash Equivalents, End of Year	$ 34,789	$ 23,767	$ 16,245

The increase in net cash provided by operating activities in 2021 over 2020 was due primarily to SPP financial transactions, most of which were related to the February extreme weather event. 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 system costs for the then current year. 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 will 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 overall wholesale and retail base rates for 2022, 2021 and 2020. However, a wholesale rate study was performed in 2021 and there were changes in individual demand and energy rates, effective February 1, 2022, as a result of the study. For retail, 2022 marks the ninth year without a base rate increase. In addition to keeping rates stable, the District has offered new rate options to its customers. New in 2021, residential customers could choose a RateWise Time-of-Use rate which allows customers on this rate to save by shifting energy usage to certain times of the day. The District has other rate options available to its retail customers which encourage customer control over consumption to save on their bills. 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% accumulated limit. The refunds implemented on February 1, 2022, 2021 and 2020 amounted to $74.2 million, $73.2 million and $46.1 million, respectively. The PCA equates to a one-year average bill reduction for wholesale customers of 10.1%, 10.2% and 6.2%, compared to base rates for the respective 12-month periods beginning February 1, 2022, 2021 and 2020. The PCA also resulted in an average annual decrease for retail customers of 3.9%, 3.9% and 3.5% compared to base rates for the respective 12-month periods beginning February 1, 2022, 2021 and 2020. Details of the District's Retail and Wholesale Power Contracts are included in Note 12.C., *Retail Agreements and Wholesale Power Contracts,* in the Notes to Financial Statements.

Revenues from firm sales increased $5.3 million, or 0.7%, from $778.4 million in 2020 to $783.7 million in 2021. The increase was due primarily to higher retail industrial energy sales and wholesale energy sales. 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 in revenues was due primarily to a larger refund to wholesale customers through the PCA rate, 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 Participation Sales

Revenues from participation sales increased from $64.7 million in 2020 to $66.7 million in 2021, an increase of $2.0 million, or 3.1%. The increase was due primarily to higher demand revenues from participants for Gerald Gentleman Station. 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 Cooper Nuclear Station and increased capacity sales.

Revenues from Other Sales

Other sales consist of sales in SPP's Integrated Market and nonfirm sales to other utilities. Other sales increased from $106.3 million in 2020 to $386.6 million in 2021, an increase of $280.3 million, or 263.7%. The increase was due primarily to SPP financial transactions, most of which were related to the high SPP market prices during the February extreme weather event. Other sales decreased from $165.6 million in 2019 to $106.3 million in 2020, a decrease of $59.3 million. The decrease was due primarily to lower prices in the SPP Integrated Market, a decrease in energy sales due to the Cooper Nuclear Station planned refueling and maintenance outage and other fossil station outages.

Other Operating Revenues

Other operating revenues consist primarily of revenues for transmission and other miscellaneous revenues. These revenues were $72.3 million, $71.8 million and $77.6 million in 2021, 2020 and 2019, respectively. The majority of these revenues were from SPP transmission customers. The decrease in revenues from 2019 to 2020 was due primarily to lower SPP transmission revenues from customers for their share of qualifying transmission upgrade projects of the District. Such decreases were 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.

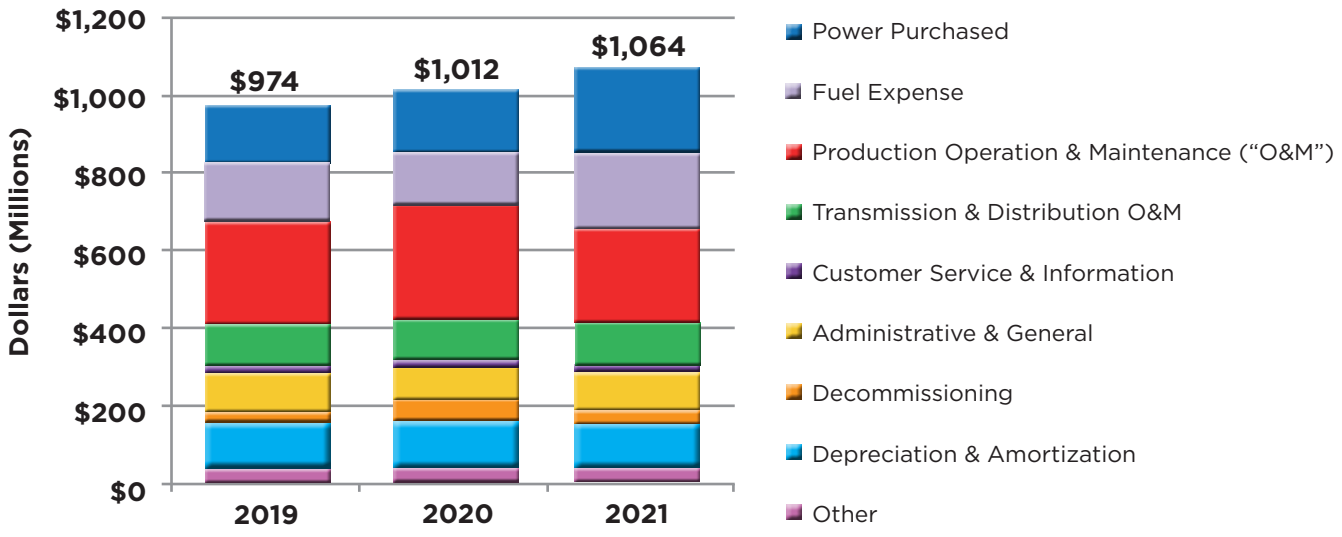
The following table shows the increase (decrease) in revenues from rate stabilization and other regulatory accounts for the years 2021, 2020 and 2019, respectively (in 000's).

	2021	2020	2019
Surplus revenues deferred to future periods	$ (144,556)	$ (14,883)	$ (71,292)
Refunded revenues from prior periods	78,049	75,794	56,645
CNS outage collections	(21,000)	21,000	(21,000)
	$ (87,507)	$ 81,911	$ (35,647)

The balance of the regulatory liability for unearned revenues to be applied as credits against revenue requirements in future rate periods was $268.1 million, $201.6 million and $262.5 million, as of December 31, 2021, 2020 and 2019, respectively.

Operating Expenses

The following chart illustrates operating expenses for the years ended December 31, 2019 through 2021.



Total operating expenses in 2021 were $1,064.3 million, an increase of $52.5 million over 2020. Total operating expenses in 2020 were $1,011.8 million, an increase of $37.7 million over 2019. The changes were due primarily to the following:

Power purchased expenses were $219.9 million, $168.2 million and $154.9 million in 2021, 2020 and 2019, respectively. These expenses increased $51.7 million in 2021 over 2020 due primarily to additional expenses from the SPP Integrated Market related to the February 2021 extreme weather event and demand charges for NC2, which were partially offset by reduced expenses for the wind agreements. Power purchased 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 Gerald Gentleman Station.

Fuel expenses were $198.7 million, $141.6 million and $166.7 million in 2021, 2020 and 2019, respectively. These expenses increased $57.1 million in 2021 from 2020 due primarily to natural gas and fuel oil purchases at high prices during the February 2021 extreme weather event and additional coal expenses in 2021 for higher generation from this fuel source. Fuel expenses decreased $25.1 million in 2020 from 2019 due primarily to reduced generation at Cooper Nuclear Station for the planned refueling and maintenance outage, Gerald Gentleman Station and Sheldon Station unplanned outages and low market prices.

Production operation and maintenance expenses were $230.1 million, $271.6 million and $238.5 million in 2021, 2020 and 2019, respectively. These expenses decreased $41.5 million in 2021 from 2020 due primarily to the planned refueling and maintenance outage at Cooper Nuclear Station in 2020 and expense reductions realized from TEA related to the February extreme weather event in 2021. These decreases in expenses were partially offset by higher operations and maintenance costs incurred for Gerald Gentleman Station, Sheldon Station and Canaday Station related to increased generation and outage work in 2021. Production operation and maintenance expenses increased $33.1 million in 2020 over 2019 due primarily to the planned refueling and maintenance outage at Cooper Nuclear Station in 2020.

Transmission and distribution operation and maintenance expenses were $112.3 million, $106.7 million and $104.4 million in 2021, 2020 and 2019, respectively. These costs increased $5.6 million in 2021 as compared to 2020 due primarily to additional SPP expenses. Transmission and distribution operation and maintenance expenses increased $2.3 million in 2020 as compared to 2019 due primarily to additional expenses for maintenance and vegetation management.

Customer service and information expenses were $15.6 million, $16.1 million and $15.9 million in 2021, 2020 and 2019, respectively.

Administrative and general expenses were $100.8 million, $90.7 million and $102.0 million in 2021, 2020 and 2019, respectively. These expenses increased $10.1 million in 2021 over 2020 due primarily to higher costs for salaries and benefits, outside services and settlements for injuries and damages, along with lower capitalization of these costs as a result of lower capital expenditures in 2021. Administrative and general 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.

Decommissioning expenses were $25.2 million, $52.7 million and $28.5 million in 2021, 2020 and 2019, 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 decreased $27.5 million in 2021 as compared to 2020 due primarily to a decrease in investment income for decommissioning funds. These costs increased $24.2 million in 2020 as compared to 2019 due primarily to an increase in investment income for decommissioning funds and additional expenses for non-nuclear assets.

Depreciation and amortization expenses were $121.8 million, $126.2 million and $125.0 million in 2021, 2020 and 2019, respectively. The decrease of $4.4 million in 2021 from 2020 was due primarily to lower depreciation and amortization costs related to retail customers. Depreciation and amortization expenses increased $1.2 million in 2020 over 2019 due primarily to the amortization of costs related to lease plant improvements for retail customers.

Investment and Other Income

Investment and other income were $14.6 million, $51.6 million and $47.1 million in 2021, 2020 and 2019, respectively. The decrease of $37.0 million in 2021 as compared to 2020 was due primarily to a decrease in investment income for decommissioning funds and lower interest rates. The increase of $4.5 million in 2020 as compared to 2019 was due primarily to increased investment income on decommissioning fund investments.

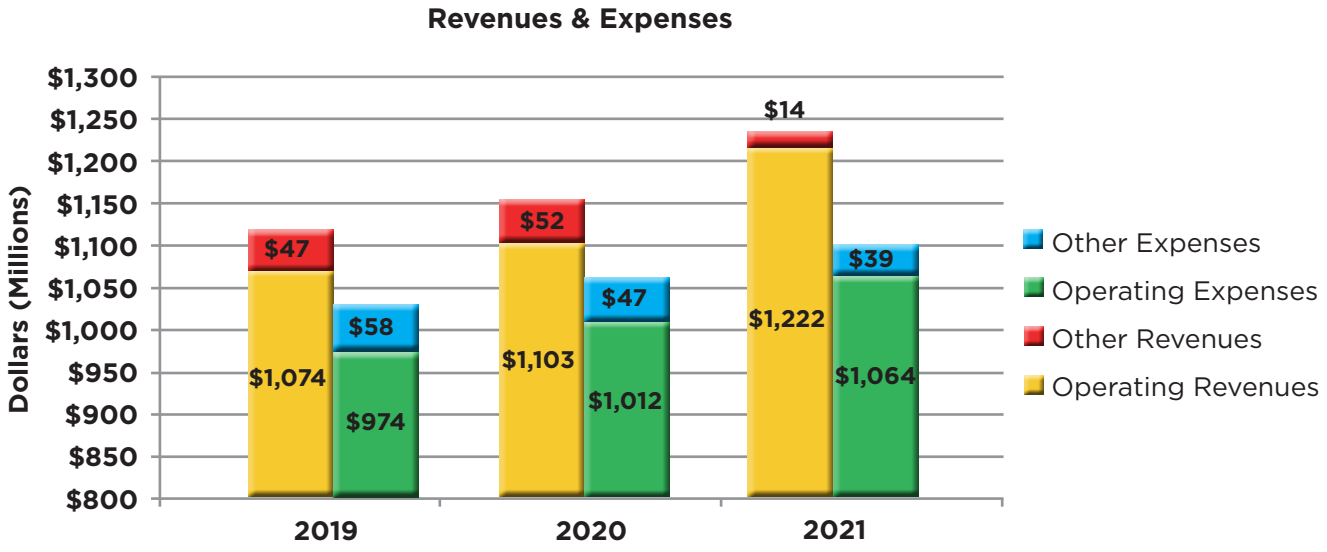
Debt and Related Expenses

Debt and related expenses were $39.0 million, $47.0 million and $58.2 million in 2021, 2020 and 2019, respectively. The decreases of $8.0 million from 2020 to 2021 and $11.2 million from 2019 to 2020 were due primarily to a reduction in interest expense from lower interest rates, a reduction in average debt outstanding and the use of operating funds instead of debt for nuclear fuel purchases.

Increase in Net Position

The increase in net position was $133.1 million, $95.9 million and $89.2 million in 2021, 2020 and 2019, respectively. The change in net position in 2021 as compared to 2020 increased $37.2 million and was due primarily to an increase in revenues for principal payments for debt service and construction from revenue. 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 following chart illustrates the District's operating revenues, other revenues, operating expenses and other expenses for the years ended December 31, 2019 through 2021.



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 for payments to those municipalities served by the District under long-term PRO Agreements. The District's debt service coverage ratio was 2.71, 1.89 and 2.18 in 2021, 2020 and 2019, respectively. The increase in the 2021 debt service coverage ratio over 2020 was due primarily to additional net revenues. 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. For additional detail, refer to the Calculation of Debt Service Ratios in the Required Supplementary Information.

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 General 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 end of the term of the 2016 Contracts. 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.

The District may issue additional General Revenue Bonds in 2022 to finance or refinance capital costs for its capital improvement plan. The District may at any time also issue bonds to refund any existing indebtedness. The District expects to continue to finance with indebtedness a prior year SPP Notification to Construct capital project for approximately 225 miles of 345 kV transmission line (the "R-Project"), which has an SPP approved estimated cost of $462.7 million as published by SPP in the first quarter of 2022. The District previously issued General Revenue Bonds, 2020 Series A, to finance a portion of the costs of the R-project.

The District also uses tax-exempt and taxable revolving credit agreements for financing needs, ("TERCA" and "TRCA"), respectively. The Board authorized additional TERCA principal payments of $60.0 million in 2021 for the Production level of service due to the favorable financial performance in 2021. Details of the District's debt balances and activity are included in Note 7 in the Notes to Financial Statements.

CAPITAL REQUIREMENTS

The Board-approved capital projects totaled approximately $163.4 million, $94.9 million and $154.5 million in 2021, 2020 and 2019, respectively. The District's capital requirements are funded with monies generated from operations, debt proceeds and other available reserve funds.

Capital projects for 2021 included:

- $70.4 million for 345kV and 115kV line and substation additions and upgrades
- $14.5 million for SAP S/4HANA and SAP Analytics Cloud Planning technical software upgrades and advancements
- $7.8 million for Cooper Nuclear Station 316(b) environmental modifications
- $4.9 million for North Platte Hydro penstock exterior coating
- $4.9 million for physical access control system ("PACS") software/card readers/biometrics
- $4.1 million for hydraulic Keystone gate recoating
- $4.0 million for Pauline to Mark Moore transmission line conductor replacement
- $3.0 million for July 2021 storm damage

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 Gerald Gentleman Station Unit No. 2
- $3.6 million for a generator stator rewind at Beatrice Power Station

Capital projects for 2019 included:

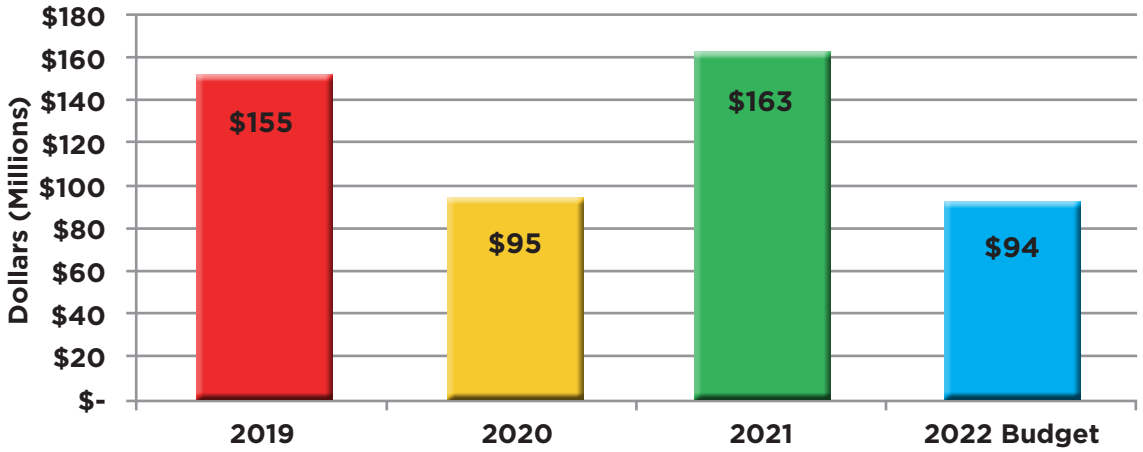
- $53.1 million amendment resulting in a new project cost of $417.3 million for the R-Project, an SPP Notification to Construct project, for a high-voltage transmission line approved in prior years
- $9.8 million to replace Secondary Superheat Intermediate Bank Pendants at Gerald Gentleman Station
- $9.4 million to replace remaining retail customer meters with two-way Advanced Metering Infrastructure
- $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 Cooper Nuclear Station

There were other authorized capital projects for renewals and replacements to existing facilities and other additions and improvements of $49.8 million, $62.3 million and $71.1 million for 2021, 2020 and 2019, respectively.

The Board-approved budget for capital projects for 2022 is $94.4 million. Specific capital projects for 2022 include:

- $8.6 million for transmission line breaker and relay replacement
- $7.3 million for Gerald Gentleman Station 316(b) environmental modifications
- $6.6 million for SCADA and Outage Management System integrated technology solution implementation/ upgrade
- $3.7 million for Firth substation and capacitor bank, an SPP Notification to Construct Project
- $2.1 million for mobile field and plant technology
- $2.0 million for data governance

The following chart illustrates the Board-approved capital projects for the years ended December 31, 2019 through 2021, including the Board-approved budget for the year ended December 31, 2022.



TRANSMISSION LINE – THE R-PROJECT

The District received an SPP Notification 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 Gerald Gentleman Station, north to a substation east of Thedford, then eastward 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 sufficient transmission access. Additional information on the R-Project is in the Notes to Financial Statements, specifically Note 12.D., *SPP Membership and Transmission Agreements,* and Note 12.F., *Environmental, Endangered Species Act*.

FEBRUARY 2021 EXTREME WEATHER EVENT

During the week of February 14 through February 20, 2021, there was an extreme weather event that impacted the area served by SPP (including Nebraska), as well as neighboring regional transmission organizations. A combination of factors resulted in a significant reduction in the availability of accredited generation in SPP and resulted in SPP ordering limited rolling outages on two consecutive days during this event. The District's generation operated reliably during the event, which contributed to the record financial performance the District achieved.

The net impact to the District from the extreme weather event (net of reductions for realized settlements of financial hedges, payments to participants, related variable costs for fuel and other operating expenses) was favorable by approximately $152.0 million.

MONOLITH MATERIALS, INC.

Monolith Materials, Inc., ("Monolith") is a retail industrial customer of Norris Public Power District, a firm wholesale customer of the District. Monolith produces carbon black at their Olive Creek facility, which became fully operational in 2020. Monolith plans to expand the facility. The District and Monolith executed a Letter of Intent ("the LOI") outlining the interest of the parties to supply Renewable Energy Credits ("REC") for Monolith's facilities. The LOI is subject to termination by either party as provided in the LOI. Pursuant to the LOI, the District solicited bids from renewable energy developers in 2021. 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 purchasing such energy and REC. Due to numerous uncertainties including potential federal legislation, supply chain issues, regulatory approvals and other factors, the District and Monolith continue to evaluate the process for the purchase of renewable energy and REC. The District will also need to invest in additional transmission facilities for the Olive Creek facility expansion. The District received a Notification to Construct from SPP for some of the transmission facilities required for the expansion.

SUPPLY CHAIN DISRUPTION ISSUES

The District, like many other electric utilities, experienced supply chain disruption issues at the end of 2021 and these issues have continued in 2022 for certain materials and supplies. These supply chain issues have been attributed to adverse impacts on production outputs related to COVID-19. Issues affecting the planned non-nuclear production outages are being managed. Materials for the 2022 Cooper Nuclear Station refueling and maintenance outage have been received. However, there may be material delays experienced for unplanned outages, restoration efforts from storms and when responding to customer requests.

TERMINATION OF AGREEMENT WITH ENTERGY

In March 2022, the District and Entergy Corporation ("Entergy") announced their mutual agreement to terminate the Entergy Agreement for support services at Cooper Nuclear Station, with a target date no later than July 31, 2022. The agreement has been in place since 2003. The District will continue operating Cooper Nuclear Station and will utilize Entergy and other available industry resources, as appropriate. The change management plan includes actions to update the Corporate Oversight Plan that will leverage Cooper Nuclear Station's participation in the Utilities Services Alliance to maintain and leverage fleet experience. The District and Entergy are currently negotiating the formal agreement to terminate the relationship. This decision will result in cost savings to the District. Additional information is in the Notes to Financial Statements, specifically Note 12.E., *Cooper Nuclear Station.*

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 customers' needs. The non-carbon energy resources as a percentage of native load sales were 63% and 62% for 2021 and 2020, respectively. A five-year Integrated Resource Plan ("IRP") was last approved by the Board in 2018. Activities are underway for the preparation of an updated IRP, with an expected completion date of 2023. The IRP will take into consideration the District goal, which was approved by the Board in 2021, for net zero carbon emissions from generation resources by 2050, while maintaining affordability, reliability and system resiliency.

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 between 2010 and 2019 and one year of decrease between 2019 and 2020, Nebraska's inflation-adjusted, estimated gross state product increased by 4.0% from the third quarter of 2020 to the third quarter of 2021. The U.S. economy experienced a 4.9% increase in real national gross domestic product over the same 12-month period.

Declines in Nebraska's "Retail Trade" (-7.6%), "Wholesale Trade" (-5.7%), "Military" (-4.9%), and "Finance and Information" (-2.8%) sectors were offset by increases in "Agriculture, Forestry, Fishing and Hunting" (+52.5%), "Arts, Entertainment and Recreation" (+20.4%), "Administrative and Support and Waste Management and Remediation Services" (+16.0%) and "Accommodation and Food Services" (+11.9%).

Despite strong demand for goods and services, in 2021 and continuing in 2022, supply constraints led to higher prices and lost production. These constraints included lack of inputs, due to supply chain disruptions, and labor shortages. Due to a lower labor force participation rate, there was upward pressure on wages. This upward pressure led to higher rates of inflation in 2021. The average annual inflation rate for 2021 was 4.7% and monthly inflation rates for January and February 2022 were 7.5% and 7.9% respectively. Gasoline prices and natural gas supply issues exacerbated by the Russia-invasion of Ukraine are expected to challenge economic growth in the U.S. and Nebraska economies in 2022.

Nebraska and the Midwest region continue to experience unemployment rates below the national average. Nebraska's preliminary average annual unemployment rate decreased from the revised 2020 value of 4.1% to 2.5% in 2021. This was well below the 2021 national average unemployment rate of 5.3%. Nebraska's preliminary, seasonally-adjusted unemployment rate was 2.3% in December 2021, down from the revised 2.8% in December 2020. Both numbers were well below the national December seasonally-adjusted unemployment rates of 3.9% in 2021 and 6.7% in 2020. Nebraska's preliminary December 2021 unemployment rate tied for lowest in the nation with Utah. The District continues to monitor changes in national and global economic conditions, which could impact operating costs, 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:

- supply chain disruption issues for certain materials and equipment,
- labor shortage issues,
- 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, and potential aggregation of certain energy products at the retail distribution level for sale into wholesale markets,
- "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, including distributed generation,
- electrification of transportation sectors,
- issues relating to cyber and physical security,
- increasing costs and challenges building electric transmission facilities, and
- growing expectations among some large customers for renewable/clean energy supply options.

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. Such agreements are only binding upon the parties to the agreement.

Report of Independent Auditors

To the Board of Directors of Nebraska Public Power District

Opinion

We have audited the accompanying financial statements of 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, 2021 and 2020, 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, including the related notes (collectively referred to as the District's "basic financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the business-type activities and the fiduciary activities of Nebraska Public Power District as of December 31, 2021 and 2020, and the 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.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the District and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management 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, and for 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.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the District's ability to continue as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit 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, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the District's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Required Supplemental Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis and supplemental schedules on pages 7 through 22 and 58 through 60 be presented to supplement the basic financial statements. Such information is the responsibility of management, 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 supplemental 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 audit 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

Management is responsible for the other information included in the annual report. The other information comprises the statistical section, but does not include the basic financial statements and our auditors' report thereon. Our opinion on the basic financial statements does not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the basic financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the basic financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

PricewaterhouseCoopers LLP

Chicago, Illinois
April 14, 2022

Statements of Net Position - Business-Type Activities

Nebraska Public Power District

As of December 31, (in 000's)	2021	2020
ASSETS AND DEFERRED OUTFLOWS		
Current Assets:		
Cash and cash equivalents	$ 34,789	$ 23,767
Investments	707,295	590,811
Receivables, less allowance for doubtful accounts of $522 and $510, respectively	115,498	111,139
Fossil fuels, at average cost	31,817	27,628
Materials and supplies, at average cost	120,830	115,256
Prepayments and other current assets	16,839	15,503
	1,027,068	884,104
Special Purpose Funds:		
Construction funds	19,040	32,777
Debt service and reserve funds	73,409	81,632
Employee benefit funds	2,106	3,963
Decommissioning funds	694,287	706,200
	788,842	824,572
Utility Plant, at Cost:		
Utility plant in service	5,204,057	5,152,673
Less reserve for depreciation	3,034,216	2,951,378
	2,169,841	2,201,295
Construction work in progress	243,245	230,751
Nuclear fuel, at amortized cost	105,507	139,335
	2,518,593	2,571,381
Other Long-Term Assets:		
Regulatory asset for other postemployment benefits	84,273	120,944
Long-term capacity contracts	125,023	131,967
Unamortized financing costs	6,145	6,808
Investment in The Energy Authority	21,821	9,420
Net other postemployment benefit asset	34,527	-
Other	4,430	6,378
	276,219	275,517
Total Assets	4,610,722	4,555,574
Deferred Outflows of Resources:		
Asset retirement obligation	102,502	35,100
Unamortized cost of refunded debt	3,214	26,227
Other postemployment benefits	43,834	40,424
	149,550	101,751
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 4,760,272	$ 4,657,325
LIABILITIES, DEFERRED INFLOWS, AND NET POSITION		
Current Liabilities:		
Revenue bonds, current	$ 63,535	$ 79,140
Revolving credit agreements, current	-	113,999
Accounts payable and accrued liabilities	71,754	72,327
Accrued in lieu of tax payments	9,865	9,750
Accrued payments to retail communities	2,391	2,121
Accrued compensated absences	20,582	20,726
Other	12,211	11,308
	180,338	309,371
Long-Term Debt:		
Revenue bonds, net of current	1,123,341	1,323,489
Revolving credit agreements, net of current	159,793	21,919
	1,283,134	1,345,408
Other Long-Term Liabilities:		
Asset retirement obligation	800,855	743,860
Net other postemployment benefit liability	-	22,940
Other	27,507	25,388
	828,362	792,188
Total Liabilities	2,291,834	2,446,967
Deferred Inflows of Resources:		
Unearned revenues	268,096	201,589
Other deferred inflows	313,062	254,552
	581,158	456,141
Net Position:		
Net investment in capital assets	1,340,481	1,245,645
Restricted	22,194	30,044
Unrestricted	524,605	478,528
	1,887,280	1,754,217
TOTAL LIABILITIES, DEFERRED INFLOWS, AND NET POSITION	$ 4,760,272	$ 4,657,325

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)	2021	2020
Operating Revenues	$ 1,221,778	$ 1,103,149
Operating Expenses:		
Power purchased	219,941	168,232
Production:		
Fuel	198,693	141,578
Operation and maintenance	230,096	271,603
Transmission and distribution operation and maintenance	112,318	106,668
Customer service and information	15,554	16,115
Administrative and general	100,785	90,691
Payments to retail communities	30,119	28,252
Decommissioning	25,165	52,688
Depreciation and amortization	121,777	126,215
Payments in lieu of taxes	9,906	9,795
	1,064,354	1,011,837
Operating Income	157,424	91,312
Investment and Other Income:		
Investment income	12,368	49,307
Other income	2,240	2,322
	14,608	51,629
Increase in Net Position Before Debt and Other Expenses	172,032	142,941
Debt and Related Expenses:		
Interest on revenue bonds	52,730	59,787
Allowance for funds used during construction	(1,492)	(3,466)
Bond premium amortization net of debt issuance expense	(13,315)	(11,695)
Interest on revolving credit agreements	1,046	2,423
	38,969	47,049
Increase in Net Position	133,063	95,892
Net Position:		
Beginning balance	1,754,217	1,658,325
Ending balance	$ 1,887,280	$ 1,754,217

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)	2021	2020
Cash Flows from Operating Activities:		
Receipts from customers and others	$ 1,244,530	$ 991,172
Other receipts	454	339
Payments to suppliers and vendors	(552,809)	(523,968)
Payments to employees	(272,268)	(262,112)
Net cash provided by operating activities	419,907	205,431
Cash Flows from Investing Activities:		
Proceeds from sales and maturities of investments	3,809,008	3,775,452
Purchases of investments	(3,921,383)	(3,698,352)
Income received on investments	17,962	51,142
Net cash provided by (used in) investing activities	(94,413)	128,242
Cash Flows from Capital and Related Financing Activities:		
Proceeds from issuance of revenue bonds	318,623	125,825
Proceeds from revolving credit agreements	131,556	76,105
Capital expenditures for utility plant	(128,312)	(202,772)
Contributions in aid of construction and other reimbursements	21,993	27,594
Principal payments on revenue bonds	(490,465)	(124,250)
Interest payments on revenue bonds	(54,773)	(60,940)
Interest paid on defeased revenue bonds	(4,877)	-
Principal payments on revolving credit agreements	(107,681)	(167,340)
Interest payments on revolving credit agreements	(999)	(2,709)
Other non-operating revenues	463	2,336
Net cash used in capital and related financing activities	(314,472)	(326,151)
Net increase (decrease) in cash and cash equivalents	11,022	7,522
Cash and cash equivalents, beginning of year	23,767	16,245
Cash and cash equivalents, end of year	$ 34,789	$ 23,767
Reconciliation of Operating Income to Cash Provided By Operating Activities:		
Operating income	$ 157,424	$ 91,312
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation and amortization	121,777	126,215
Undistributed net revenue - The Energy Authority	684	210
Decommissioning, net of customer contributions	12,752	38,757
Amortization of nuclear fuel	34,726	35,025
Changes in assets and liabilities which provided (used) cash:		
Receivables, net	(7,497)	3,834
Fossil fuels	(4,189)	(3,870)
Materials and supplies	(5,574)	(3,020)
Prepayments and other current assets	(1,822)	558
Other long-term assets	-	(501)
Accounts payable and accrued payments to retail communities	6,949	(17,309)
Unearned revenues	66,507	(60,911)
Other deferred inflows	35,437	(5,494)
Other liabilities	2,733	625
Net cash provided by operating activities	$ 419,907	$ 205,431
Supplementary Non-Cash Capital Activities:		
Change in utility plant additions in accounts payable	$ (6,880)	$ (1,138)

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)	2021	2020
Assets:		
Cash and cash equivalents	$ 29,967	$ 7,134
Receivables:		
Investment income	467	487
Investments	372,177	336,331
Total Assets	402,611	343,952
Liabilities:		
Payables:		
Benefits - healthcare	44	216
Benefits - life insurance	58	38
Investment expense	31	116
Professional, administrative and other expenses	136	32
Total liabilities	269	402
Net Position - Restricted for Other Postemployment Benefits	$ 402,342	$ 343,550

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)	2021	2020
Additions:		
Contributions		
Employer	$ 28,283	$ 28,283
Investment Income:		
Net appreciation in fair value of investments	43,137	43,642
Interest and dividends	4,028	4,229
Total investment income	47,165	47,871
Less: Investment expenses	(686)	(634)
Net investment income	46,479	47,237
Total additions	74,762	75,520
Deductions:		
Health care benefits	15,493	13,807
Life insurance benefits	218	218
Professional, administrative and other expenses	259	205
Total deductions	15,970	14,230
Increase in Net Position	58,792	61,290
Net Position - Restricted for Other Postemployment Benefits		
Beginning balance	343,550	282,260
Ending balance	$ 402,342	$ 343,550

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 Statements of Net Position, 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 Statements of Net Position.

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 2.1% and 2.3% for the years ended December 31, 2021 and 2020. The District had fully depreciated utility plant, primarily related to Cooper Nuclear Station, which was still in service of $1,364.6 million and $1,344.8 million as of December 31, 2021 and 2020, respectively.

The District's retail service territory includes 77 municipal-owned distribution systems operated by the District within the State of Nebraska for the municipality pursuant to a Professional Retail Operations Agreement ("PRO Agreement") and two retail communities in South Dakota. 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 $8.0 million and $12.7 million in 2021 and 2020, respectively, which was included in depreciation and amortization expense. These utility plant additions, which were fully amortized, totaled $218.2 million and $220.0 million as of December 31, 2021 and 2020, 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 the tax-exempt revolving credit agreement ("TERCA") or the 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 1.0% for 2021 and 2.5% for 2020.

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 ("ARO") –*
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 asset or 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 ("ARR") and Transmission Congestion Rights ("TCR") –*
The District uses ARR and 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 Statements of Net Position 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 deferred outflow for the unamortized cost of refunded debt is the remaining cost to be amortized. 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, Cooper Nuclear Station 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, 2021 and 2020 and activity for the years then ended (in 000's):

	2021	2020
Unearned revenues, beginning of year	$ 201,589	$ 262,500
Surpluses	144,556	14,883
Use of prior period rate stabilization funds in rates	(78,049)	(75,794)
Unearned revenues, end of year	$ 268,096	$ 201,589

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 Cooper Nuclear Station. Details of the District's DOE settlements are included in Note 12.E., *Cooper Nuclear Station,* 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 Cooper Nuclear Station 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.E., *Cooper Nuclear Station,* in the Notes to Financial Statements.

In 2021, the District collected revenues for the costs of the 2022 Cooper Nuclear Station refueling and maintenance outage. This regulatory liability was included in Other deferred inflows on the Statements of Net Position and will be amortized through revenue during 2022, 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 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 Statements of Net Position 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 Statements of Net Position.

The following table summarizes the balance of Other deferred inflows of resources as of December 31, 2021 and 2020 (in 000's):

	2021	2020
DOE settlements	$ 78,311	$ 78,311
Nuclear fuel disposal collections	45,412	39,013
CNS outage collections	21,000	-
Settlements for termination of agreements	30,456	34,660
Unrealized OPEB gains	93,481	69,274
Non-nuclear decommissioning collections	41,032	29,641
Renewable energy facility sales tax refund	3,370	3,653
	$ 313,062	$ 254,552

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 revolving credit agreements 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 revolving credit agreements 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 Statements of Net Position. 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 were 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 as it relates to its revolving credit agreements. Management will continue to evaluate other reference rates and the impact of this statement. LIBOR will continue to be published through June 2023.

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 an unrealized net loss of $3.0 million in 2021 and an unrealized net gain $0.5 million in 2020, respectively.

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

	2021		2020	
	Fair Value	Weighted Average Maturity (Years)	Fair Value	Weighted Average Maturity (Years)
U.S. Treasury and government agency securities	$ 943,442	3.5	$ 972,798	2.8
Corporate bonds	221,767	15.3	223,507	15.4
Municipal bonds	9,951	13.9	22,094	13.7
Cash and cash equivalents	355,766	0.2	220,751	0.2
Total cash and investments	$ 1,530,926		$ 1,439,150	
Portfolio weighted average maturity		4.5		4.5

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 Statements of Net Position, except Cash and cash equivalents in the Revenue Fund investment account are reported as Investments.

	2021	2020
Revenue funds - Cash and cash equivalents	$ 34,789	$ 23,767
Revenue funds - Cash equivalents in investments	305,161	168,045
Revenue funds - Investments	402,134	422,766
	$ 742,084	$ 614,578

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 General Revenue Bond proceeds and the issuance of short-term debt.

	2021	2020
Construction funds - Cash and cash equivalents	$ 381	$ -
Construction funds - Investments	18,659	32,777
	$ 19,040	$ 32,777

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 $22.2 million and $30.0 million as of December 31, 2021 and 2020, 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 $51.2 million and $51.6 million as of December 31, 2021 and 2020.

	2021	2020
Debt service and reserve funds - Investments	$ 73,409	$ 81,632

The Employee Benefit funds consist of a self-funded hospital-medical benefit plan for active employees only as of December 31, 2021 and 2020. The District pays 85% of the hospital-medical premiums with the employees paying the remaining 15% of the cost of such coverage.

	2021	2020
Employee benefit funds - Cash and cash equivalents	$ 2,106	$ 3,963

The Decommissioning funds are utilized to account for the investments held to fund the estimated cost of decommissioning Cooper Nuclear Station 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.

	2021	2020
Decommissioning funds - Cash and cash equivalents	$ 13,328	$ 24,976
Decommissioning funds - Investments	680,959	681,224
	$ 694,287	$ 706,200

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 Codification Section 3100, *Fair Value Measurement*, includes 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 by GASB 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 Codification Section 3100. 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 Codification Section 3100 as of December 31, 2021 and 2020.

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):

	2021			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 494,201	$ -	$ 494,201
Cash and cash equivalents	342,438	-	-	342,438
Decommissioning funds:				
U.S. Treasury and government agency securities	-	449,241	-	449,241
Corporate bonds	-	221,767	-	221,767
Municipal bonds	-	9,951	-	9,951
Cash and cash equivalents	13,328	-	-	13,328
	$ 355,766	$1,175,160	$ -	$ 1,530,926

	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

4. UTILITY PLANT:

Utility plant activity for the year ended December 31, 2021, was as follows (in 000's):

	December 31, 2020	Increases	Decreases	December 31, 2021
Nondepreciable utility plant:				
Land and improvements	$ 79,232	$ 87	$ -	$ 79,319
Construction in progress	230,751	103,643	(91,149)	243,245
Total nondepreciable utility plant	309,983	103,730	(91,149)	322,564
Nuclear fuel*	139,335	898	(34,726)	105,507
Depreciable utility plant:				
Generation - Fossil	1,678,206	29,697	(11,960)	1,695,943
Generation - Nuclear	1,347,068	9,346	(1,683)	1,354,731
Transmission	1,403,254	25,268	(2,413)	1,426,109
Distribution	262,996	20,729	(22,221)	261,504
General	381,917	7,994	(3,460)	386,451
Total depreciable utility plant	5,073,441	93,034	(41,737)	5,124,738
Less reserve for depreciation	(2,951,378)	(124,575)	41,737	(3,034,216)
Depreciable utility plant, net	2,122,063	(31,541)	-	2,090,522
Utility plant activity, net	$ 2,571,381	$ 73,087	$ (125,875)	$ 2,518,593

* Nuclear fuel decreases represented amortization of $34.7 million.

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.

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 $57.7 million and $53.2 million as of December 31, 2021 and 2020, respectively. The unamortized amount of the plant capacity contract was $120.7 million and $125.3 million as of December 31, 2021 and 2020, respectively, of which $4.4 million was included in Prepayments and other current assets as of December 31, 2021 and 2020. The District's share of NC2 working capital was also included in Prepayments and other current assets and was $7.3 million and $7.1 million as of December 31, 2021 and 2020, 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 and Central entered into a power purchase agreement which is to remain in effect until the hydro unit is retired and removed from commercial operation; however, the District has the right to terminate said Agreement upon notice and payment to Central of all of its costs attributable to the acquisition, construction, and operation of the hydro unit. The District is amortizing the contract on a straight-line basis over the 40-year estimated useful life of the facility. Accumulated amortization was $75.8 million and $73.5 million as of December 31, 2021 and 2020, respectively. The unamortized amount of the Central capacity contract was $10.8 million and $13.1 million as of December 31, 2021 and 2020, respectively, of which $2.3 million was included in Prepayments and other current assets as of December 31, 2021 and 2020.

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 $1.8 million and $2.3 million in 2021 and 2020, 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, 2021 and 2020. In addition to the District, the following utilities have interests of 17.65% each as of December 31, 2021: 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, 2021: City Utilities of Springfield, Missouri and Gainesville Regional Utilities (Florida).

Such investment was $21.8 million and $9.4 million as of December 31, 2021 and 2020, 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.

As a member of TEA, the District made payment of a membership fee and certain contributions to capital and is providing certain guarantees for electric trading and other activities by TEA. Such guarantees have been authorized as Credit Obligations under the General Resolution on a parity with the General Revenue Bonds. The guarantees include $25.0 million to support business growth and trading due to TEA's California Community Aggregation program that provides for TEA or others to supply electricity to communities that were previously served by investor-owned utilities. The District was obligated to guaranty, directly or indirectly, a share of TEA's electric trading activities. The total amount guaranteed by the District for TEA's electric trading and other activities, including the California Community Aggregation Program, was up to $53.9 million, as of December 31, 2021, 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 guarantees 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, 2021 and 2020.

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, 2021 and 2020, and debt activity for 2021 (in 000's):

	Total Debt at December 31, 2020	Increases	Decreases	Total Debt at December 31, 2021	Long-Term Debt at December 31, 2021	Current Liabilities at December 31, 2021
Revenue bonds	$ 1,402,629	$ 318,623	$ (534,376)	$ 1,186,876	$ 1,123,341	$ 63,535
Revolving credit agreements	135,918	131,556	(107,681)	159,793	159,793	-
Total debt activity	$ 1,538,547	$ 450,179	$ (642,057)	$ 1,346,669	$ 1,283,134	$ 63,535

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

General Revenue Bonds

In October 2021, the District issued $106.4 million of General Revenue Bonds, 2021 Series C at a premium of $19.2 million and $30.8 million of General Revenue Bonds, 2021 Series D at a premium of $4.4 million for the principal purpose of refunding certain of the District's outstanding General Revenue Bonds, 2012 Series A, 2013 Series A, 2014 Series A, 2014 Series C, and 2015 Series A-2. The refunding was completed with $137.2 million of the proceeds from the General Revenue Bonds 2021 Series C and D, a $95.0 million draw from the TERCA and $7.6 million of other available funds. As a result, total debt service payments over the life of the bonds are expected to be reduced by $108.8 million, which will result in total present value savings of $97.9 million.

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 settled in 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 from indebtedness a prior year SPP Notification to Construct capital project for approximately 225 miles of 345 kV transmission line (the "R-Project") which has an SPP approved estimated cost of $462.7 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 $142.7 million through December 31, 2021, for design, construction mobilization and easement acquisitions. Additional information on the R-Project is in the Notes to Financial Statements, specifically Note 12.D., *SPP Membership and Transmission Agreements,* and Note 12.F., *Environmental, Endangered Species Act*.

Congressional action reduced the 35.0% 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 5.9% for fiscal years ended September 30, 2021 and 2020, respectively.

There were outstanding principal amounts aggregating $503.2 million and $93.4 million from legal defeasances of General Revenue Bonds, 2012 Series A, 2013 Series A, 2014 Series A, 2014 Series C, 2015 Series A-2, and 2017 Series A, as of December 31, 2021 and 2020, respectively.

The General Revenue 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 Revenue 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, 2021, are as follows (in 000's):

Year	Debt Service Payments	Principal Payments
2022	$ 108,162	$ 63,535
2023	158,550	112,635
2024	118,819	77,705
2025	122,259	84,515
2026	103,473	69,340
2027-2031	418,373	289,710
2032-2036	280,306	209,570
2037-2041	141,112	111,510
2042-2046	60,691	51,820
2047-2050	20,510	18,645
Total Payments	$ 1,532,255	$ 1,088,985

The fair value of outstanding General Revenue Bonds was determined using currently published rates. The fair value was estimated to be $1,242.9 million and $1,457.0 million as of December 31, 2021 and 2020, 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 $63.8 million and $21.9 million as of December 31, 2021 and 2020, respectively. As such, the remaining credit available under TERCA was $86.2 million and $128.1 million as of December 31, 2021 and 2020, respectively. The outstanding amount is anticipated to be retired by future collections through electric rates and the issuance of General Revenue Bonds. The carrying value approximates market value. 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 Revenue 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 Revenue 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 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 $95.9 million and $114.0 million, as of December 31, 2021 and 2020, respectively. As such, the remaining credit available under TRCA, using the allowance to increase the loan commitments to $300.0 million, was $204.1 million and $186.0 million as of December 31, 2021 and 2020, 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. The agreement was renewed on July 29, 2021, with a termination date of July 26, 2024.

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 Revenue 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 Revenue 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-”.

General Revenue Bonds consist of the following (in 000's except interest rates):

December 31,	Interest Rate	2021	2020
General Revenue Bonds:			
2010 Series A Taxable Build America Bonds:			
Serial Bonds: 2021–2024	4.38% - 4.73%	$ 16,595	$ 21,825
Term Bonds: 2025–2029	5.323%	27,985	27,985
2030–2042	5.423%	54,190	54,190
2012 Series A Serial Bonds 2021–2034	3.00% - 5.00%	-	117,570
2012 Series B:			
Serial Bonds: 2021–2032	2.875% - 5.00%	45,505	55,970
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	5.00%	-	62,680
2014 Series A:			
Serial Bonds: 2021–2038	3.50% - 5.00%	-	85,020
Term Bonds: 2039–2043	4.00%	-	31,650
2039–2043	4.125%	-	1,945
2014 Series C Serial Bonds 2021–2033	5.00%	-	63,720
2015 Series A-1 Serial Bonds 2022–2034	3.00% - 5.00%	119,400	119,400
2015 Series A-2:			
Serial Bonds: 2021–2034	3.00% - 5.00%	-	49,760
Term Bonds: 2035–2039	5.00%	-	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 2021–2035	5.00%	50,945	55,235
2016 Series D:			
Serial Bonds: 2021–2035	3.00% - 5.00%	17,510	18,410
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 2021–2027	2.00% - 5.00%	2,870	4,230
2017 Series B Serial Bonds 2021–2027	5.00%	33,605	40,470
2019 Series A Serial Bonds 2021–2034	5.00%	31,400	33,125
2019 Series B-1 Taxable Serial Bonds 2021–2028	2.063% - 2.593%	73,215	74,095
2019 Series B-2 Taxable Serial Bonds 2021–2028	2.063% - 2.593%	16,015	16,215
2020 Series A Serial Bonds 2024–2050	0.60%	125,825	125,825
2021 Series A Serial Bonds 2022–2039	5.00%	75,525	-
2021 Series B Serial Bonds 2022–2040	5.00%	52,080	-
2021 Series C Serial Bonds 2022–2031	5.00%	106,350	-
2021 Series D:			
Serial Bonds: 2022–2026	5.00%	12,085	-
Term Bonds: 2041–2043	4.00%	18,720	-
Total par amount of General Revenue Bonds		1,088,985	1,314,690
Unamortized premium net of discount		97,891	87,939
		1,186,876	1,402,629
Less – current maturities of General Revenue Bonds		(63,535)	(79,140)
Long-term General Revenue Bonds		$1,123,341	$1,323,489

8. PAYMENTS IN LIEU OF TAXES:

The District is required to make payments in lieu of taxes, aggregating 5.0% 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 $9.9 million and $9.8 million for the years ended December 31, 2021 and 2020, 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	2021	2020
CNS license termination costs	$ 782,000	$ 730,568
GGS and Sheldon ash landfills	10,932	10,228
Ainsworth	6,923	2,064
Underground storage tanks	1,000	1,000
	$ 800,855	$ 743,860

The District is required by the Nuclear Regulatory Commission ("NRC") to decommission Cooper Nuclear Station after cessation of plant operations, consistent with regulations in the U.S. Code of Federal Regulations. The Cooper Nuclear Station 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 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. The inflation rates used were 7.04% and 1.36% for the years 2021 and 2020, respectively. The District has funds set aside for decommissioning of $694.3 million and $706.2 million as of December 31, 2021 and 2020, 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 Gerald Gentleman Station and Sheldon Station, consistent with their regulations. As GASB guidance is unclear related to the accounting treatment for ash landfill AROs, guidance in GASB Codification Section A10, *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 Gerald Gentleman Station and Sheldon Station, 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 Gerald Gentleman Station and Sheldon Station, respectively. The rate of 7.04% in the CPI-U was used to adjust for inflation in 2021. The inflation rate of 1.21% used to adjust the obligations for 2020 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 Gerald Gentleman Station and Sheldon Station. The costs included in rates for the decommissioning of the ash landfills were $0.9 million and $1.0 million for 2021 and 2020, 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 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 Wind Energy Facility has an estimated closure date of September 30, 2025. The 2021 ARO was based on an external study completed in 2021 for costs using one scenario. The 2020 ARO was based on an external study completed in 2015. The ARO for the 2015 study was annually adjusted for inflation. The CPI-U rate of 1.36% was used in 2020 for the inflation adjustment. There are no legally required funding and assurance provisions associated with this ARO. The costs included in rates for the decommissioning of Ainsworth Wind Energy Facility were $0.2 million for both 2021 and 2020. These rate collections reduced the related deferred outflow for Ainsworth Wind Energy Facility.

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 1,947 and 1,915 active Plan members as of December 31, 2021 and 2020, 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 up to 5.0% 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 $17.2 million and $16.5 million for 2021 and 2020, respectively. The District's matching contributions were $16.0 million and $15.6 million for 2021 and 2020, respectively. Total contributions of $1.7 million and $1.6 million were accrued in accounts payable and accrued liabilities as of December 31, 2021 and 2020, respectively.

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 $2.7 million and $2.5 million for 2021 and 2020, 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. The Board authorized an increase in these annual amounts to $4,120 and $2,060 for 2022. These benefits were included for the first time in the actuarial valuation as of January 1, 2021. 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:

	2021	2020
Active employees	1,893	878
Inactive employees in retirement status	1,419	1,392
Inactive employees in long-term disability status	49	48
Total employees covered by benefit terms	3,361	2,318

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

	2021	2020
Active employees	1,893	1,888
Inactive employees in retirement status	1,279	1,230
Inactive employees in long-term disability status	53	56
Total employees covered by benefit terms	3,225	3,174

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 for 2021 and 2020.

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 for 2021 and 2020. 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 (Asset) Liability –*

The District's net OPEB asset was measured as of January 1, 2021, and its net OPEB liability was measured as of January 1, 2020. For each of these measurement dates, the total OPEB liability was used to calculate the net OPEB asset/liability and was determined by an actuarial valuation as of these dates.

Actuarial Assumptions and Methods

The actuarial assumptions and methods used in the January 1, 2021 and 2020, respectively actuarial valuation were based on the results of an actuarial experience study completed during 2018. The total OPEB liability in the January 1, 2021 and 2020, respectively, 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
Healthcare cost trend rates	Pre-Medicare: 6.7% initial for 2021, ultimate 4.5% Post-Medicare: 7.1% initial for 2021, ultimate 4.5% Pre-Medicare: 7.1% initial for 2020, ultimate 4.5% Post-Medicare: 7.8% initial for 2020, ultimate 4.5%
Administrative cost trend	3.0%
Inflation	2.1% for 2021 and 2.2% for 2020
Salary increases	4.0%
Investment rate of return	6.0% for 2021 and 6.25% for 2020, net of investment expense, including inflation
Discount rate	6.0% for 2021 and 6.25% for 2020, 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-2020 for 2021 Pub-2010 "General" table with generational projection using Scale MP-2019 for 2020
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	2021 Long-Term Expected Real Rate of Return	2020 Long-Term Expected Real Rate of Return
Equity and Real Estate	70%	6.9%	7.2%
Fixed income	30%	2.0%	3.0%
	100%	5.7%	6.2%

Discount Rate

The discount rate used to measure the total OPEB liability was 6.0% and 6.25% for the actuarial valuations as of January 1, 2021 and 2020, respectively. 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. For the roll-forward valuation dated December 31, 2021, the discount rate was lowered to 5.75%.

C. Changes in the Net OPEB (Asset) Liability –

The following table shows the total OPEB liability, plan fiduciary net position and net OPEB asset as of January 1, 2021, and the changes during this period, based on the valuation measurement date of January 1, 2021 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB (Asset) Liability (a-b)
Balances at January 1, 2020	$ 305,200	$ 282,260	$ 22,940
Changes for the year:			
Service cost	2,103	-	2,103
Interest	18,775	-	18,775
Changes of benefit terms	8,598	-	8,598
Differences between expected and actual experience	(20,995)	-	(20,995)
Changes of assumptions	9,367	-	9,367
Contributions - employer	-	28,283	(28,283)
Net investment income	-	47,237	(47,237)
Benefit payments	(14,026)	(14,026)	-
Administrative expense	-	(205)	205
Net changes	3,822	61,289	(57,467)
Balances at January 1, 2021	$ 309,022	$ 343,549	$ (34,527)

There were changes made in certain assumptions for the valuation measurement date of January 1, 2021. The mortality assumptions were updated to the Pub-2010 "General" table with generational projection using Scale MP-2020. The healthcare trend rates were also updated. The changes in benefit terms for 2021 were for the addition of the RRA.

Sensitivity of the Net OPEB (Asset) Liability to Changes in the Discount Rate

The following table shows the net OPEB asset of the District, as well as what the net OPEB asset would be if it were calculated using a discount rate that is 1-percentage-point lower (5.0%) or 1-percentage-point higher (7.0%) than the discount rate (6.0%) at the measurement date of January 1, 2021 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB (Asset) Liability	$ 3,411	$ (34,527)	$ (66,309)

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

The following table shows the net OPEB asset of the District, as well as what the net OPEB asset would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 5.7% initial to 3.5% ultimate, Post-Medicare ranging from 6.1% initial to 3.5% ultimate) or 1- percentage-point higher (Pre-Medicare ranging from 7.7% initial to 5.5% ultimate, Post-Medicare ranging from 8.1% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 6.7% initial to 4.5% ultimate, Post-Medicare ranging from 7.1% initial to 4.5% ultimate) at the measurement date of January 1, 2021 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB (Asset) Liability	$ (65,166)	$ (34,527)	$ 1,981

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

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 $8.4 million for 2021, as calculated under GASB Codification Section P50, *Postemployment Benefits Other Than Pensions-Reporting for Benefits Provided through Trusts that Meet Specified Criteria-Defined Benefit,* which was 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 2021.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2021 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ 74	$ 49,489
Changes in assumptions	7,990	1,571
Difference between actual and expected earnings	7,487	42,421
Contributions made during the year ended December 31, 2021	28,283	-
	$ 43,834	$ 93,481

The deferred outflows of resources related to the contributions made during the year ended December 31, 2021 will be recognized in the actuarial valuation with a measurement date of January 1, 2022. 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
2022	$ (20,678)
2023	(18,343)
2024	(20,820)
2025	(12,198)
2026	(4,523)
2027	(1,368)
Total	$ (77,930)

OPEB expense was negative $3.2 million for 2020, as calculated under the GASB guidance, 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 were 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
2020	$ (12,389)
2021	(13,151)
2022	(10,816)
2023	(13,293)
2024	(4,671)
2025	(2,813)
Total	$ (57,133)

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 $295.0 million at December 31, 2021. These contracts expire at various times through the end of 2027. 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 2024, a contract for enrichment services and a contract for fabrication services through January 18, 2034, the end of the current operating license of Cooper Nuclear Station. These commitments for nuclear fuel material and services have combined estimated future payments of $210.0 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 160.0% 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 Gerald Gentleman Station and Cooper Nuclear Station 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 8.0% of the net power and energy of Gerald Gentleman Station. In return, Lincoln agrees to pay 8.0% of all costs (excluding fuel costs) attributable to Gerald Gentleman Station. This agreement is to terminate upon the later of the last maturity of the debt attributable to Gerald Gentleman Station 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 for 2022. Western announced a rate increase, which would be effective January 1, 2023, subject to future rate hearings. The annual minimum future payments with the rate increase are approximately $32.2 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 which terminate on September 30, 2025. 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 a summer 2021 accredited net capacity of 41.7 MW. The District and Central entered into a power purchase agreement which is to remain in effect until the hydro unit is retired and removed from commercial operation; however, the District has the right to terminate said Agreement upon notice and payment to Central of all of its costs attributable to the acquisition, construction, and operation of the hydro unit.

C. *Retail Agreements and Wholesale Power Contracts –*

Retail Agreements

The District 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 2037 and 2045. These 77 retail PRO Agreement customers represented 72.2% of retail revenues for 2021. The remaining two PRO Agreements are being actively worked for renewal and expire in 2029 and 2030. 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.

Wholesale Power Contracts

The District serves its wholesale customers under total and partial 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 Contracts ("2016 Contracts") with 22 public power districts, one cooperative, and 37 municipalities. One public power district and 9 municipalities were served under the 2002 Contracts ("2002 Contracts"), which expired 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 2016 to 2020 set forth in the CFC Data:

CFC Data	
Year	Percentile
2016	28.2%
2017	26.0%
2018	26.9%
2019	29.5%
2020	23.2%

There were ten wholesale customers on the 2002 Contracts which expired on December 31, 2021. In 2021, these customers purchased at least 10% of their demand and energy from the District.

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 has received an SPP Notification 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 Gerald Gentleman Station, north to a substation east of Thedford, then eastward 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 sufficient transmission access. The R-Project construction is currently delayed because of litigation which is discussed further in this Note in section 12.F., *Environmental, Endangered Species Act*.

A bill has been introduced into the Nebraska Legislature which 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. No action was taken on the bill in the 2021 Legislative Session. The bill remains in the Executive Board Committee and it will carry over to the 2022 Legislative Session.

The District, as the owner of the R-Project, had previously entered into a generator interconnection agreement with SPP and Thunderhead Wind Energy LLC ("Thunderhead"), that would allow the proposed Thunderhead Wind Energy Center to interconnect at the Holt County substation, which is to be constructed and owned by the District, and is in the eastern terminus of the R-Project. In 2021, FERC approved a revised generator interconnection agreement and settlement agreement that changed the scope of the generator interconnection agreement to include construction of the majority of the Holt County substation. This change transfers an estimated $11.0 million in construction costs from the R-Project to the generator interconnection agreement and, upon completion, would allow limited operation of the Thunderhead Wind Energy Center. If the R-Project fails to obtain the required permitting and regulatory approvals and the District decides to terminate the R-Project, the District would request SPP to withdraw its Notification to Construct the R-Project. If the SPP Board approves said notice to withdraw, the District would be required to provide SPP information relating to the costs incurred for the R-Project.

The escalated cost of the R-Project is $462.7 million, as published by SPP in the first quarter of 2022. The District awarded a contract for the construction of the R-Project in January 2019. The District has spent approximately $142.7 million through December 31, 2021, for design, construction mobilization, purchase of lattice tower steel, 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 Cooper Nuclear Station for an additional 20 years until January 18, 2034. Cooper Nuclear Station entered the 20-year period of extended operation on January 18, 2014.

In October 2003, the District entered into an agreement for support services at Cooper Nuclear Station with 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 18.0% 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 $16.2 million and $16.1 million for 2021 and 2020, respectively. In March 2022, the District and Entergy announced their mutual agreement to terminate the Entergy Agreement for Cooper Nuclear Station, with a target date no later than July 31, 2022. As the agreement to terminate was mutual, neither party will pay a termination charge.

Cooper Nuclear Station 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 Cooper Nuclear Station 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 Cooper Nuclear Station 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 Cooper Nuclear Station 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 2021. 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 Cooper Nuclear Station. The balance in the regulatory liability was $78.3 million as of December 31, 2021 and 2020.

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 Cooper Nuclear Station, 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 Cooper Nuclear Station 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, 2021, Cooper Nuclear Station 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 Cooper Nuclear Station 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. The next refueling and maintenance outage is currently planned for the fall of 2022.

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 Cooper Nuclear Station are paying the costs. The regulatory liability for the pre-collection of outage costs was $21.0 million as of December 31, 2021 and will be eliminated through revenue recognition during the 2022 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 ("NPDES") permits. NDEE issued the District permits for the following facilities: Gerald Gentleman Station, Sheldon Station, Cooper Nuclear Station, Beatrice Power Station, Canaday Station and the North Platte Office Building. The NPDES permits for Cooper Nuclear Station and Gerald Gentleman Station require the installation of 316(b) environmental modifications. The District is currently in the engineering and design phase at both facilities. The current estimated costs for this technology at Cooper Nuclear Station and Gerald Gentleman Station are $7.8 million and $7.3 million, respectively.

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 Cooper Nuclear Station, Gerald Gentleman Station, Sheldon Station and Canaday Station, the Effluent Rule only has an impact on Sheldon Station. Sheldon Station 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: Gerald Gentleman Station, Sheldon Station, 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 2027, the District expects to have sufficient Acid Rain allowances to cover affected facilities through 2027, 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 Gerald Gentleman Station and Sheldon Station, 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 2027, the District expects to have sufficient CSAPR allowances to cover affected facilities emission requirements through 2027, 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 Gerald Gentleman Station 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 Gerald Gentleman Station. 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 Gerald Gentleman Station NO_x portion of the SIP but disapproved the SO_2 portion of the SIP for Gerald Gentleman Station. The EPA issued a Federal Implementation Plan ("FIP") for Gerald Gentleman Station which stated that BART for SO_2 control at Gerald Gentleman Station 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. The NDEE did not make this deadline and plans to submit the SIP in late 2022.

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 Gerald Gentleman Station 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 Gerald Gentleman Station 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 has provided information including detailed air modeling results. The District and the NDEE continue to meet and discuss this matter. 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 Gerald Gentleman Station, it could affect the future economic viability of the station.

Clean Power Plan

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 SIP. 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 ("HRI") 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 HRI technologies listed in the final ACE rule at Gerald Gentleman Station 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 SIP.

It was announced on January 19, 2021 that the D.C. Circuit Court vacated the ACE rule. This action stopped further development of the SIP by the NDEE.

On February 28, 2022, the Supreme Court heard oral arguments on appeals to reinstate the ACE rule. A ruling on the appeal is expected to be issued in the Summer of 2022 and will likely impact any future regulations.

Endangered Species Act –

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, took 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 will continue to keep the site in a stable condition while the R-Project construction remains 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.

Impact from Changes to Environmental Regulatory Requirements –
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. *Spencer Hydro -*
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.

The District has been working with the Federal Emergency Management Agency ("FEMA") to make appropriate claims for reimbursement for the Spencer Hydro Facility. FEMA required a detailed study on the cost of rebuilding and the cost of removing the Spencer Hydro Facility, which the District pursued through an engineering firm. The study and cost estimates were submitted to FEMA. The study estimated the cost of decommissioning to be approximately $9.4 million. The District expects to eventually remove the Spencer Hydro Facility, which will require approval from the Nebraska Department of Natural Resources (the "NDNR") and permitting from other state and federal agencies.

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 was settled in February 2022. 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 in early stages of discovery. At this time, it is not possible to predict the outcome.

13. LITIGATION:

Information on litigation related to the R-Project and the USFWS is included in Note 12.F., *Environmental-Endangered Species Act.*

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

In 2017 and 2021, the Nebraska Department of Revenue ("NDOR") conducted sales and use tax audits on the District's records for the audit periods of June 1, 2014 through May 31, 2017 and June 1, 2017 through May 31, 2021, respectively. For both audits, NDOR issued Notices of Deficiency Determination to the District. Beyond the minor sales and use tax corrections contained in a normal audit Determination, the most significant disagreements between the District and NDOR relate to NDOR's assessment of tax on the payments to municipalities under PRO Agreements. The District filed Petitions for Redetermination to formally challenge the Deficiency Determinations on March 29, 2018 and January 28, 2022, respectively. A hearing on the 2017 audit was held on November 16, 2021. A decision has not yet been issued for this hearing. The District has paid all taxes and interest charges related to items in which the District agreed taxes were owed for these audits. State legislation was passed in 2019 that exempted the payments under PRO Agreements from sales and use tax. The remaining disputed tax balances, excluding interest and penalties, for the Notices issued by NDOR are $4.1 million and $5.5 million, respectively.

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:

Termination of the Entergy Agreement -
In March 2022, the District and Entergy announced their mutual agreement to terminate the Entergy Agreement for support services at Cooper Nuclear Station, with a target date no later than July 31, 2022. Additional information related to the Agreement is included in Note 12.E, *Cooper Nuclear Station*.

REQUIRED SUPPLEMENTARY INFORMATION (UNAUDITED)

Calculation of Debt Service Ratios in accordance with the General Revenue Bond Resolution for the years ended December 31, (in 000's)	2021	2020
Operating revenues	$ 1,221,778	$ 1,103,149
Operating expenses	(1,064,354)	(1,011,837)
Operating income	157,424	91,312
Investment and other income	14,608	51,629
Debt and related expenses	(38,969)	(47,049)
Increase in net position	133,063	95,892
Add:		
Debt and related expenses[1]	38,969	47,049
Depreciation and amortization[2]	121,777	126,215
Payments to retail communities[3]	30,119	28,252
Amortization of current portion of financed nuclear fuel[4]	25,490	32,622
Amounts collected from third party financing arrangements[5]	-	541
	216,355	234,679
Deduct:		
Investment income retained in construction funds[6]	162	341
Unrealized gain (loss) on investment securities	(2,976)	460
	(2,814)	801
Net revenues available for debt service under the General System Bond Resolution	$ 352,232	$ 329,770
General system bonded debt service[7]	130,138	174,606
Ratio of net revenues available for debt service[7]	2.71	1.89

(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 PRO 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) 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. The increase in the 2021 debt service coverage ratio over 2020 was due primarily to additional net revenues. The debt service coverage for 2020 included 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.

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

Total OPEB Liability	2021	2020	2019	2018	2017	2016
Service Cost	$ 2,103	$ 2,299	$ 2,771	$ 2,760	$ 3,322	$ 3,229
Interest	18,775	19,604	19,661	20,032	20,658	19,876
Changes of Benefit Terms	8,598	-	-	-	-	-
Differences between Expected and Actual Experiences	(20,995)	(19,961)	(8,686)	(19,570)	(203)	13,657
Changes of Assumptions	9,367	(1,608)	(751)	5,585	(18,807)	(9,149)
Benefit Payments, net of employee contributions	(14,026)	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Net Change in Total OPEB Liability	3,822	(12,473)	(1,065)	(6,607)	(8,489)	10,711
Total OPEB Liability (Beginning)	305,199	317,672	318,737	325,344	333,833	323,122
Total OPEB Liability (Ending) (a)	$ 309,021	$ 305,199	$ 317,672	$ 318,737	$ 325,344	$ 333,833
Plan Fiduciary Net Position						
Contributions	$ 28,283	$ 41,084	$ 56,706	$ 28,439	$ 74,711	$ 28,242
Net Investment Income (Loss)	47,237	41,733	(6,892)	21,350	6,102	(453)
Benefit Payments, net of employee contributions	(14,026)	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Administrative Expense	(205)	(188)	(130)	(70)	(69)	(150)
Net Change in Plan Fiduciary Net Position	61,289	69,822	35,624	34,305	67,285	10,737
Plan Fiduciary Net Position (Beginning)	282,260	212,438	176,814	142,509	75,224	64,487
Plan Fiduciary Net Position (Ending) (b)	$ 343,549	$ 282,260	$ 212,438	$ 176,814	$ 142,509	$ 75,224
Net OPEB (Asset) Liability (Ending) (a) - (b)	$ (34,528)	$ 22,939	$ 105,234	$ 141,923	$ 182,835	$ 258,609
Net Position as a % of Total OPEB Liability	111.2%	92.5%	66.9%	55.5%	43.8%	22.5%

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

	2021	2020	2019	2018	2017	2016
Actuarially Determined Contribution	$ 2,871	$ 6,676	$ 12,967	$ 18,572	$21,006	$ 28,283
Contributions Made in Relation to the Actuarially Determined Contribution	28,283	28,283	41,084	56,706	28,439	74,712
Contribution Deficiency (Excess)	$(25,412)	$(21,607)	$(28,117)	$(38,134)	$ (7,433)	$(46,429)

Schedules of Investment Returns for Years Ended December 31,

	2021	2020	2019	2018	2017	2016
Annual Money-Weighted Rate of Return, Net of Investment Expense	13.3%	15.6%	18.9%	(3.6)%	14.2%	5.8%

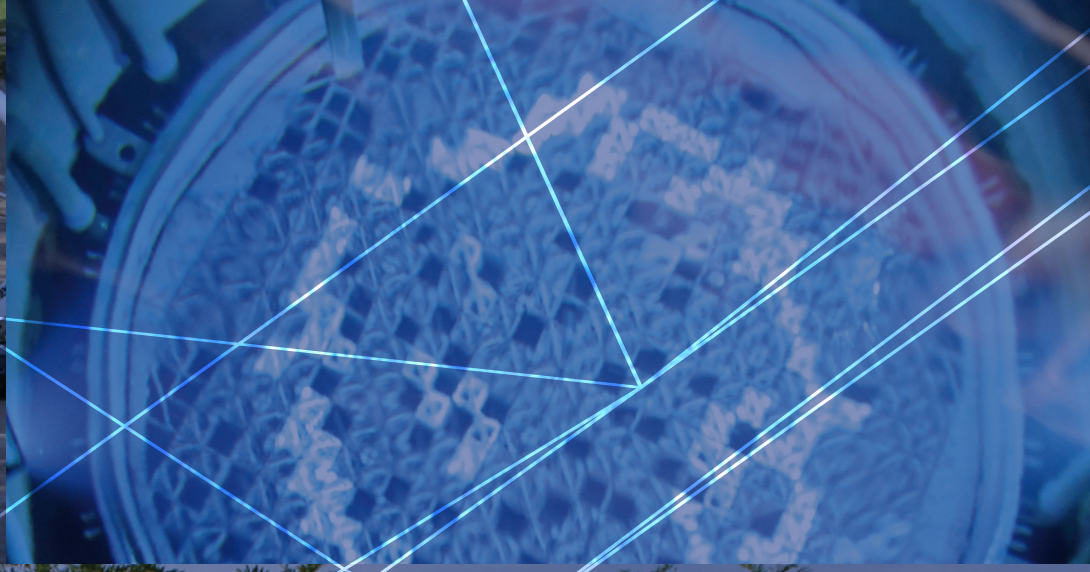
NOTES TO REQUIRED SUPPLEMENTARY INFORMATION (UNAUDITED)

GASB guidance requiring this information was implemented by the District in 2016. The OPEB schedules are intended to show information for ten years. Additional years will be displayed when available.

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. The changes in benefit terms for 2021 were for the addition of the RRA.

Methods and assumptions used to determine contribution rates –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	12-year closed period for 2021, 13-year closed period for 2020 14-year closed period for 2019, 15-year closed period for 2018 16-year closed period for 2017, 17-year closed period for 2016
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 6.7% initial, ultimate 4.5% for 2021 Post-Medicare: 7.1% initial, ultimate 4.5% for 2021 Pre-Medicare: 7.1% initial, ultimate 4.5% for 2020 Post-Medicare: 7.8% initial, ultimate 4.5% for 2020 Pre-Medicare: 7.4% initial, ultimate 4.5% for 2019 Post-Medicare: 8.2% initial, ultimate 4.5% for 2019 Pre-Medicare: 7.7% initial, ultimate 4.5% for 2018 Post-Medicare: 8.7% initial, ultimate 4.5% for 2018 Pre-Medicare: 7.3% initial, ultimate 4.5% for 2017 Post-Medicare: 9.1% initial, ultimate 4.5% for 2017 Pre-Medicare: 8.0% initial, ultimate 4.5% for 2016 Post-Medicare: 6.75% initial, ultimate 4.5% for 2016
Administrative cost trend	3.0%
Inflation	2.1% for 2021, 2.2% for 2020, 2.3% for 2019 and 2018, 2.1% for 2017 and 2016
Salary increases	4.0%
Investment rate of return	6.0%, net of investment expense, including inflation for 2021 6.25%, net of investment expense, including inflation for 2020 through 2016
Discount rate	6.0% for 2021, 6.25% for 2020 through 2016 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-2020 for 2021 Pub-2010 "General" table with generational projection using Scale MP-2019 for 2020 Pub-2010 "General" table with generational projection using Scale MP-2018 for 2019 RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2017 with generational projection for 2018 RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2016 with generational projection for 2017 RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2015 with generational projection for 2016
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 for 2021 through 2019 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 for 2018 through 2016
Participation rate	95% for 2021 through 2019, 100% for 2018 through 2016



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