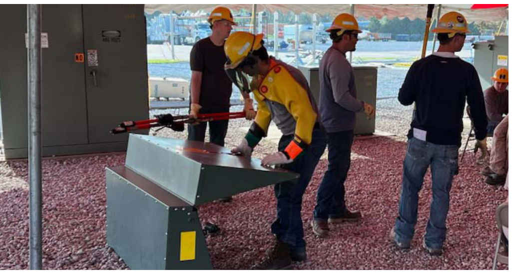
Financial Report 2023

Nebraska Public Power District

Always there when you need us





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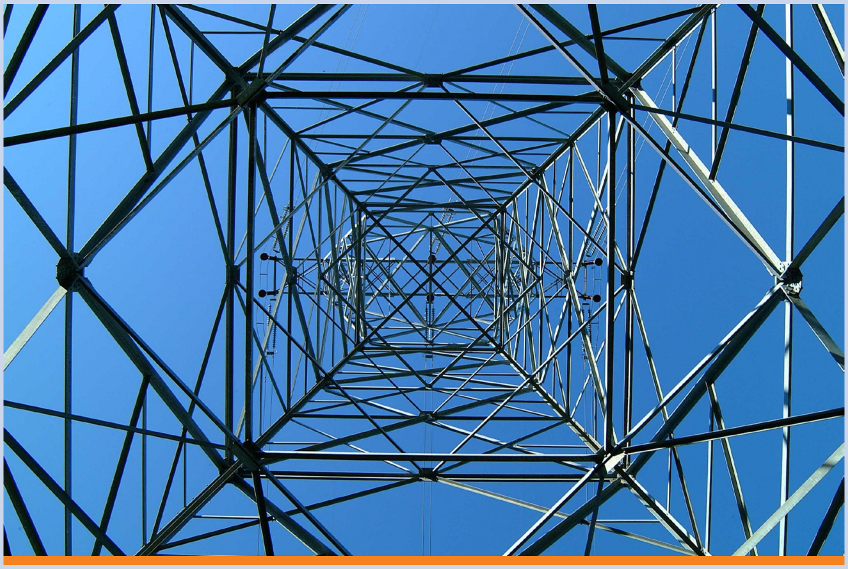


Vision

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.

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 30 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 5,377 miles of transmission and subtransmission lines and 2,827 miles of distribution lines.

Revenues are primarily derived from wholesale power supply agreements with 37 municipalities and 23 public power districts and/or cooperatives. NPPD also serves an average of more than 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 530,000 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 84 of Nebraska's 93 counties.

BY THE NUMBERS

30
GENERATING FACILITIES

5,377 MILES
TRANSMISSION & SUBTRANSMISSION LINES

2,827 MILES
DISTRIBUTION LINES

37
MUNICIPALITIES SERVED AT WHOLESALE

79
COMMUNITIES SERVED BY RETAIL

23
PUBLIC POWER DISTRICTS SERVED AT WHOLESALE

1,900+
TEAMMATES WORKING FOR YOU

$1.1 Billion
OPERATING REVENUE

530,000
NEBRASKANS SERVED IN PARTNERSHIP WITH OTHER UTILITIES

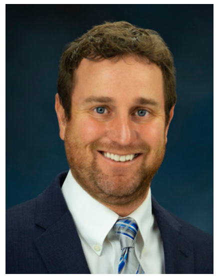
3,206MW
DIVERSE GENERATION

93,000+
RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS

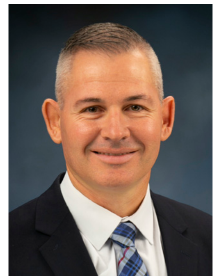
84 of 93
NEBRASKA COUNTIES ARE SERVED BY NPPD

BOARD OF DIRECTORS

Mary A. Harding
Plattsmouth
Subdivision 1



Aaron D. Troester
O'Neill
Subdivision 2



Derek S. Rusher
Kearney
Subdivision 3

David D. Gale
North Platte
Subdivision 4

Rusty M. Kemp (1)
Tryon
Subdivision 5

Edward J. Schrock
Holdrege/Elm Creek
Subdivision 6

Wayne E. Williams
Central City
Subdivision 7

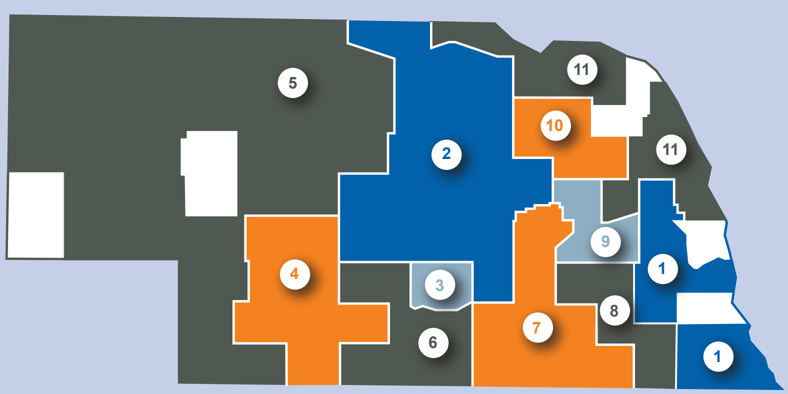
Ronald J. Mogul Jr.
York
Subdivision 8

Jerry L. Chlopek
Columbus
Subdivision 9

Sue D. Fuchtman
Norfolk
Subdivision 10

Chris R. Langemeier (2)
Schuyler
Subdivision 11

Charlie C. Kennedy (1)
Scottsbluff
Subdivision 5



Fred L. Christensen (2)
Lyons
Subdivision 11

(1) Mr. Kemp was Governor-appointed in May of 2023 following the resignation of Mr. Kennedy.
(2) Mr. Langemeier was Governor-appointed in July of 2023 following the death of Mr. Christensen.

SENIOR MANAGEMENT TEAM

Thomas J. Kent
President & Chief Executive Officer

Timothy J. Arlt (1)
Vice President, Corporate Strategy & Innovation

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

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

Courtney A. Dentlinger
Vice President, Customer Service & External Affairs & Chief Customer Officer

Khalil M. Dia
Cooper Nuclear Station Site Vice President

Laura L. Kapustka
Executive Vice President, Chief Financial Officer & Treasurer

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

Conrad L. Saltzgaber (1)
Vice President, Corporate Strategy & Transformation

Michael J. Spencer
Executive Vice President, Chief Operating Officer

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

Scott R. Walz
Vice President, Energy Delivery

Arthur R. Wiese
Vice President, Energy Production

(1) Mr. Arlt served as Vice President of Corporate Strategy and Innovation until his retirement. He was replaced by Mr. Saltzgaber on May 1, 2023.

A Message

FROM OUR 2023 BOARD CHAIR and CHIEF EXECUTIVE OFFICER

Jerry L. Chlopek
2023 Board Chair

Thomas J. Kent
President & CEO

2023 was an exciting year for NPPD. NPPD and our public power partners continue to collaborate and approach opportunities with a united focus on providing affordable, reliable, sustainable, and resilient energy to customers. This effort, and the continued success of Nebraska's public power utilities, has put us amongst the most reliable and affordable states for electric service across the U.S., reinforcing the incredible value and importance of the public power model for Nebraskans.

We had the opportunity to welcome six new directors to our Board in 2023. Sue Fuchtman of Norfolk, David Gale of North Platte, Ron Mogul, Jr. of York, and Derek Rusher of Kearney were elected in November 2022 and took office in January 2023. Rusty Kemp of rural Tryon, and Chris Langemeier of Schuyler were appointed to the NPPD Board during 2023 by Gov. Pillen to fill vacancies due to a resignation and death. The new members bring a wealth of diverse knowledge and experiences that will serve our customers and complement the longer-tenured directors on NPPD's 11-member Board.

NPPD set a record peak this past year for electricity use. The record was set on Aug. 19 with a peak of 3,087 megawatts, exceeding the previous record peak of 3,030 megawatts set in 2012. The main contributing factors to the new record were a combination of hot temperatures and high electric demand to pump water for irrigation use across our service territory.

NPPD continues to see load growth throughout our retail and wholesale partners' service territories. NPPD has been working through the process to site and build new transmission lines to support the growing loads. Our team has begun preparing for construction of new transmission lines planned around Kearney, Scottsbluff and in rural Stanton County. Building transmission is not a simple process. From identifying future local energy needs, to planning the line, working with stakeholders to site the line, and then constructing the facilities takes a full team effort. These new lines will help ensure customers in and around these areas continue to receive the safely-generated, reliable power we all enjoy, for years to come.

As we reflect on the growing load across our service territory, it's important to remember the benefits our customers receive from the diverse generation in NPPD's portfolio, and how those diverse fuels complement each other to best serve our customers. NPPD's coal units, Gerald Gentleman Station and Sheldon Station, continue to provide affordable, dispatchable energy, while Cooper Nuclear Station provides carbon-free generation around the clock. Natural gas facilities such as Beatrice Power Station, Canaday Station, and NPPD's smaller peaking units in Hallam, Hebron, and McCook, can ramp up quickly to serve load whenever they are needed. Meanwhile, our wind, hydro and community solar facilities take advantage of Nebraska's renewable energy capabilities. In combination, these generation facilities work together to bring our customers benefits from both a reliability and financial standpoint. As a member of the Southwest Power Pool, NPPD offers our generation into the market and then purchases all of our customers energy requirements from the SPP market. Thanks to the excellent work by our teammates at our generating facilities, the District continues to see our facilities regularly called into the market to serve our customers and neighbors and return financial benefits to our customers.

One of the challenges NPPD saw in 2023 came after an extreme June storm passed through the Scottsbluff area, carrying with it high winds and softball-sized hail that left much of the area heavily damaged, including the Scottsbluff community solar facility. Like all Sunwise community solar facilities in NPPD retail towns, the Scottsbluff facility was developed and operated by a private company who signed a power purchase agreement with NPPD. Thanks to the developer's commitment, in collaboration with NPPD and the community of Scottsbluff, the facility was repaired, and the damaged solar panels were sent to be recycled so they could be returned to the supply chain. This highlighted the strength of local relationships and our ability to weather any storm.

That leaves us with our final reflection from 2023, and that was the opportunity for the Board to approve another year of stable rates for both our wholesale and retail customers. Thanks to the performance of NPPD's team across the entire state, NPPD customers in our 77 Nebraska retail communities have enjoyed a decade of stable rates through 2023, while NPPD's wholesale customers experienced six years of stable rates through 2023. In addition, the NPPD Board voted to share approximately $34 million with wholesale customers in the form of a Production Cost Adjustment credit. This was the fifth consecutive year NPPD's wholesale customers received a Production Cost Adjustment credit on their bill.

Reflecting on 2023 gives us an opportunity to recognize the successes taking place across the District to provide customers with safely-generated, affordable, reliable, sustainable, and resilient power. NPPD strives to be a premier energy provider, bringing the best of public power to Nebraskans, and that vision guides us as we serve our neighbors and friends in the communities where we work and live.

2023
FINANCIAL REPORT
NEBRASKA PUBLIC POWER DISTRICT

YEAR AT A GLANCE

KILOWATT - HOUR SALES		19.3	BILLION
OPERATING REVENUES	$	1,071.9	MILLION
COST OF POWER PURCHASED AND GENERATED	$	616.0	MILLION
OTHER OPERATING EXPENSES	$	418.7	MILLION
INVESTMENT AND OTHER INCOME	$	45.7	MILLION
DEBT AND RELATED EXPENSES	$	30.8	MILLION
INCREASE IN NET POSITION	$	52.1	MILLION
DEBT SERVICE COVERAGE		1.62	TIMES

2023 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	10.42 ¢	12.49 ¢	74,046	858,419	4.4	$ 107,251	10.0
Commercial	8.21 ¢	9.71 ¢	19,724	1,080,522	5.6	104,893	9.8
Industrial	4.54 ¢	4.99 ¢	60	1,886,871	9.8	94,089	8.8
Total Retail Sales	6.90 ¢	8.00 ¢	93,830	3,825,812	19.8	306,233	28.6
Wholesale:							
Municipalities[2]		6.05 ¢	37	1,318,593	6.8	79,720	7.4
Public Power Districts and Cooperatives[2]		5.66 ¢	23	8,067,587	41.8	456,784	42.6
Total Firm Wholesale Sales		5.72 ¢	60	9,386,180	48.6	536,504	50.0
Total Firm Retail and Wholesale Sales		6.38 ¢	93,890	13,211,992	68.4	842,737	78.6
Participation and Capacity Sales		4.39 ¢	5	1,535,545	7.9	67,399	6.3
Other Sales[3]		3.91 ¢	1	4,573,134	23.7	178,701	16.7
Total Electric Energy Sales		5.64 ¢	93,896	19,320,671	100.0	1,088,837	101.6
Other Operating Revenues[4]						68,537	6.4
Unearned Revenues[5]						(85,450)	(8.0)
Total Operating Revenues						$ 1,071,924	100.0

COST OF POWER PURCHASED AND GENERATED	MWh Amount	MWh %	Costs (in 000's) Amount	Costs (in 000's) %
Production[6]	16,069,825	79.9	$ 436,859	70.9
Power Purchased	4,039,171	20.1	179,175	29.1
Total Production and Power Purchased	20,108,996	100.0	$ 616,034	100.0

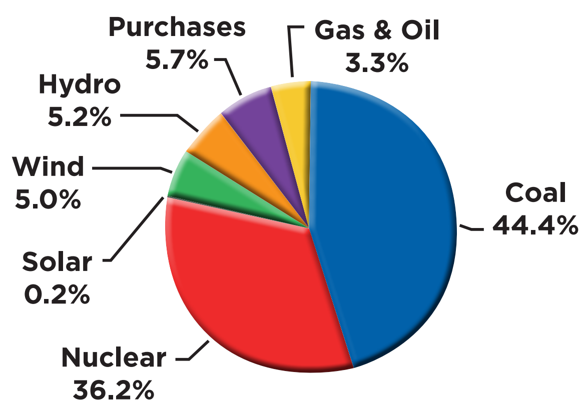
CONTRACTUAL AND TAX PAYMENTS (in 000's)[1]	Amount
Payments to Retail Communities	$ 32,407
Payments in Lieu of Taxes	10,191
Total Contractual and Tax Payments	$ 42,598

OTHER	Amount
Miles of Transmission and Subtransmission Lines in Service	5,377
Number of Full-Time Employees	1,967

(1) Customer collections for taxes/transfers to other governments are excluded from base rates.
(2) Sales are total requirements, subject to certain exceptions.
(3) Includes sales in Southwest Power Pool ("SPP") and nonfirm sales to other utilities.
(4) Includes revenues from transmission and other miscellaneous revenues.
(5) 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 ("MD&A").
(6) 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 (the "District") includes MD&A, 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 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, 2023 and 2022. The Statements of Revenues, Expenses, and Changes in Net Position present the operating results for the years 2023 and 2022. The Statements of Cash Flows present the sources and uses of cash and cash equivalents for the years 2023 and 2022. The Statements of Fiduciary Net Position present the financial resources available for other postemployment benefits ("OPEB") as of December 31, 2023 and 2022. The Statements of Changes in Fiduciary Net Position present the additions, deductions and changes in net position restricted for OPEB as of December 31, 2023 and 2022. 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, 2023 and 2022, and the results of operations for the years 2023 and 2022. 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. The District's chartered territory includes all or parts of 84 of the State's 93 counties.

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 1,967 full-time employees as of December 31, 2023. 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

The District participates in the SPP Integrated Market. Under the SPP market construct, all energy produced by the District's generating resources is sold to the market, and all energy required to serve firm requirements customers is purchased from the market. As such, the generating resources do not solely serve the District's load. When the District's generation exceeds its load, the District is a net seller. Likewise, when the District's load exceeds generation, the District is a net buyer. The District was a net seller into the SPP Integrated Market in 2023.

The District is a Load Responsible Entity ("LRE") in SPP and is required to have a capacity reserve margin above its peak demand. SPP increased this margin due to rising demand and a shift to more volatile renewables from 12.0% in 2023 to 15.0% in 2024. The highest summer peak load of 3,087.8 MW was established in August 2023 and the highest winter peak load of 2,317.5 MW was established in December 2022 for firm requirements customers.

For 2023, the District had available 3,640.2 MW of capacity resources that included 3,034.0 MW of generation capacity from 11 owned and operated generating plants and 19 plants over which the District has operating control, 443.5 MW of firm capacity purchases from the Western Area Power Administration ("Western"), and 162.7 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, 434.2 MW are being sold via participation sales or other capacity sales agreements, leaving 3,206.0 MW to serve the District's firm retail and wholesale customers and to meet capacity reserve requirements.

The following table shows the District's capacity resources from generation and respective summer 2023 accredited capacity.

	CAPACITY RESOURCES		
Type	Number of Plants(1)	Summer 2023 Accredited Capacity (MW)(2)	Percent of Total
Steam - Conventional(3)	3	1,680.3	55.4
Steam - Nuclear	1	768.5	25.3
Hydro	5	113.7	3.8
Diesel	9	67.6	2.2
Combustion Turbine(4)	3	125.9	4.2
Combined Cycle	1	219.5	7.2
Wind(5)	8	58.5	1.9
	30	3,034.0	100.0

(1) Includes three hydro plants and nine diesel plants under contract to the District.
(2) Accreditation by SPP for the summer season 2023, 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.

Load growth forecasts combined with changes in the SPP resource adequacy requirements identified a need for additional generating capacity starting in 2026. Short-term and long-term capacity purchases, battery energy storage system, combustion turbines ("CTs"), and reciprocating internal combustion engines ("RICE") are being pursued to meet these capacity needs.

In accordance with the most recent Integrated Resource Plan ("IRP"), a second license extension for Cooper Nuclear Station is also being pursued. In early 2024, the Board approved an increase in the 2024 capital budget to support these capacity additions and the Cooper Nuclear Station license extension. See the Capital Requirements section for detailed information.

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 and Capacity Sales and Other Sales, in each of the five years 2019 through 2023.

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

Year	Coal(1)	Nuclear	Hydro(2)	Wind(3)	Gas and Oil	Purchases(4)	Solar(5)
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
2022	47.5	30.1	4.7	6.2	2.4	8.9	0.2
2023	44.4	36.2	5.2	5.0	3.3	5.7	0.2

(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, except for 2019, which included purchases from JEA related to an agreement that terminated on December 31, 2019. The variances in the percentages of purchases from the SPP Integrated Market were due primarily to the weather and/or station outages. SPP purchases are recorded for differences between the amount of energy consumed by firm requirements customers and the amount of energy added by District resources, when the amount consumed is larger than the amount added in a market time period.
(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 2023 accredited capacity and in-service dates.

DISTRICT-OWNED GENERATION FACILITIES

Facility	Fuel Type	Summer 2023 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	768.5	1974
Beatrice Power Station	Combined Cycle	219.5	2005
Sheldon Station Units No. 1 and No. 2	Coal	216.0	1961, 1968
Combustion Turbines (3 generating plants)	Oil or Natural Gas	125.9	1973
Canaday Station	Natural Gas	99.3	1958
Hydro (2 generating plants)	Water	24.0	1888, 1937
Ainsworth Wind Energy Facility(2)	Wind	4.2	2005
		2,822.4	

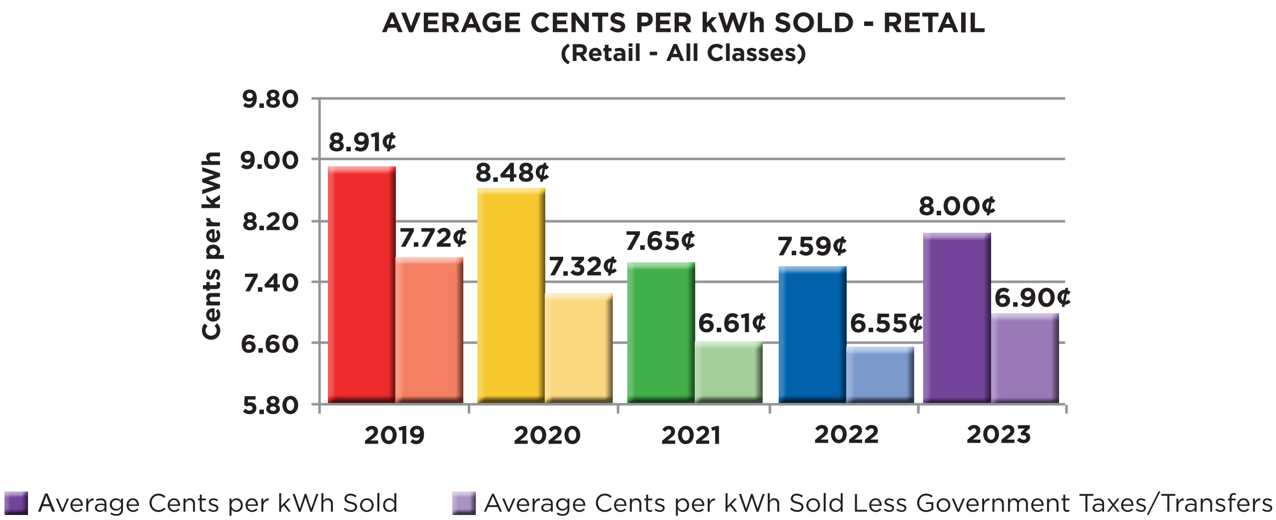
(1) 2023 summer accredited net capacity based on SPP criteria.
(2) Nominally rated at 60 MW.

THE CUSTOMERS

Retail and Wholesale Customers

In 2023, the District served an average of 93,830 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. The Village of Paxton, Nebraska entered into a PRO Agreement effective March 1, 2024, which brings the number of PRO Agreements to 80. 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.

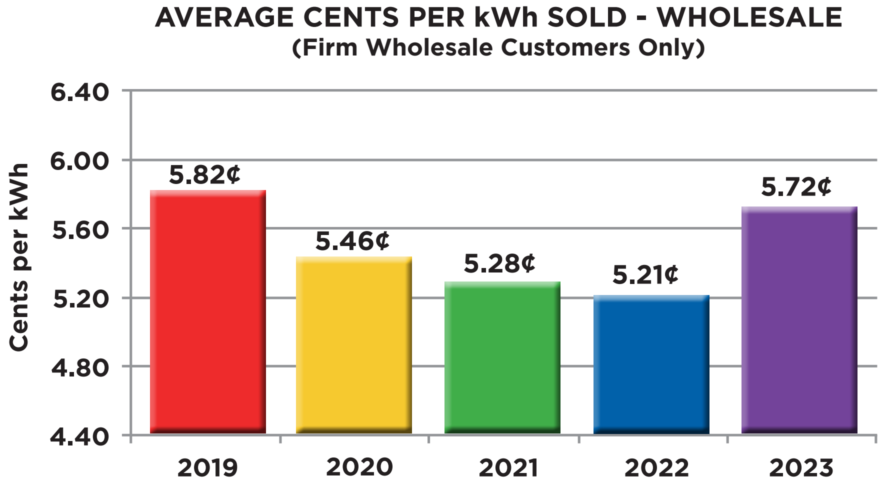
The following chart shows the District's average retail cents per kilowatt-hour ("kWh") for the years ended December 31, 2019 through 2023. The chart also shows average cents per kWh sold less customer collections for taxes and transfers to other governments, which are not included in the base rates for retail customers. The increase in the average cents per kWh sold in 2023 over 2022 was due primarily to a lower Production Cost Adjustment ("PCA") refund rate and a 6.5% decrease in energy sales in 2023, which resulted in revenues for fixed costs being averaged over fewer energy sales. The decrease in the average cents per kWh sold in 2022 from 2021 was due to a 9.2% increase in industrial energy sales in 2021 as industrial energy sales have the lowest rates of all the retail customer classes.



Wholesale Power Contracts ("2016 Contracts") with wholesale customers require them to purchase total demand and energy requirements from the District, subject to certain exceptions, through 2035. 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. The 2016 Contracts include provisions discussed below relating to a wholesale customer's right to reduce its purchases from the District. The 2016 Contracts are to continue in force after 2035 unless terminated on an anniversary thereof by at least five years' written notice given by either party, which notice may be given at any time on or after January 1, 2031. With the need to increase capacity to serve new load and finance new resources, contract discussions are underway.

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 kWh purchased, as published by the CFC Data. The District's wholesale power costs percentiles were 11.7% and 12.4% for 2022 and 2021, respectively. 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 wholesale cents per kWh for the years ended December 31, 2019 through 2023. The increase in the average cents per kWh sold in 2023 over 2022 was due primarily to a $42.3 million reduction in the actual PCA refunds. The decrease in the average cents per kWh sold in 2022 from 2021 was due to a 5.1% increase in energy sales.



Participation Sales, Capacity Sales, and Other Sales

There are participation sales agreements in place with other utilities for the sale of capacity 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 capacity and energy on a nonfirm basis in SPP and through transactions executed with other utilities by The Energy Authority ("TEA"). The participation sales agreements with MEAN for Cooper Nuclear Station and Gerald Gentleman Station terminated on December 31, 2023.

Transmission Customers

The District owns and operates 5,377 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, 2021 through 2023.

			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
2021	92,948	75	13,119,624	5.4	19,413,835	2.7	2,904.4
2022	93,485	67	13,854,281	5.6	18,947,050	(2.4)	2,946.0
2023	93,830	66	13,211,992	(4.6)	19,320,671	2.0	3,087.8

(1) For 2023, this includes sales to firm wholesale customers, participation customers (Lincoln, MEAN, OPPD and Grand Island), capacity customers and nonfirm customers. The decrease by one in 2023 from 2022 was due to a municipality becoming a retail customer of one of the District's wholesale customers. The decrease in the number of customers by eight in 2022 from 2021 was due to the contract term ending for nine customers and the addition of a capacity sale to Associated Electric Cooperative Inc. (AECI).

(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 decrease in native load sales in 2023 from 2022 was due primarily to weather and lower industrial sales. The increase in native load sales from 2021 to 2022 was due primarily to higher retail industrial energy sales and a weather-related increase in other retail and wholesale energy sales.

(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 terminated 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 in 2023 from 2022 was due primarily to an increase in nonfirm energy sales from the Cooper Nuclear Station as it was a non-outage year. The decrease in percentage growth for total sales from 2021 to 2022 was due primarily to a decrease in nonfirm energy sales as a result of the Cooper Nuclear Station planned refueling and maintenance outage and other fossil station outages.

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,	2023	2022	2021
Current Assets	$ 1,052,977	$ 956,453	$ 1,027,068
Special Purpose Funds	745,582	692,419	788,842
Utility Plant, Net	2,551,805	2,560,296	2,518,593
Other Long-Term Assets	189,999	278,312	276,219
Total Assets	4,540,363	4,487,480	4,610,722
Deferred Outflows of Resources	284,067	272,886	149,550
Total Assets and Deferred Outflows	$ 4,824,430	$ 4,760,366	$ 4,760,272
Current Liabilities	$ 304,588	$ 238,192	$ 180,338
Long-Term Debt	959,809	1,114,249	1,283,134
Other Long-Term Liabilities	878,951	868,019	828,362
Total Liabilities	2,143,348	2,220,460	2,291,834
Deferred Inflows of Resources:			
Unearned Revenues	258,311	267,758	268,096
Other Deferred Inflows	402,405	303,907	313,062
Net Position	2,020,366	1,968,241	1,887,280
Total Liabilities, Deferred Inflows, and Net Position	$ 4,824,430	$ 4,760,366	$ 4,760,272

Total Assets and Deferred Outflows

Total Assets in 2023 increased $52.9 million or 1.2% over 2022, due primarily to higher balances for investments and funds, fossil fuels, and materials and supplies. Investments and funds were higher due primarily to funds for Cooper Nuclear Station's 2024 outage and other regulatory liabilities, revenue-funded capital projects, and construction deposits. Debt service and reserve funds were higher due to deposits for capitalized interest on General Revenue Bonds, 2023 Series A. Decommissioning funds for Cooper Nuclear Station were higher due to favorable market conditions in 2023. Materials and supplies inventories were higher due to increased prices for certain inventory items because of inflation, higher demands, and/or product shortages as well as increased inventory levels for certain items for planned work activities. These increases in Total Assets were partially offset by a reduction in receivables due primarily to lower revenues in December 2023 compared to December 2022, a reduction in the net OPEB asset due to a decrease in the fiduciary net position because of unfavorable market conditions in 2022, and amortization of the regulatory asset for OPEB in 2023.

Deferred Outflows in 2023 increased $11.2 million or 4.1% over 2022, due primarily to lower-than-expected earnings from unfavorable market conditions in 2022 for the postemployment benefits trust which were included in deferred outflows for OPEB. The increase in Deferred Outflows was partially offset by a decrease in the deferred outflows for asset retirement obligations, due to an updated study for Cooper Nuclear Stations which reduced the asset retirement obligation and larger investment balances to fund asset retirement obligations from rate collections and favorable market conditions.

Total Assets in 2022 decreased $123.2 million or 2.7% from 2021, due primarily to lower balances for investments and funds and the amortization of the regulatory asset for OPEB. Decommissioning funds for Cooper Nuclear Station were lower due to unfavorable market conditions in 2022. These decreases in Total Assets were partially offset by higher balances for receivables, fossil fuels, materials and supplies, nuclear fuel, and net OPEB asset. Receivables were higher due primarily to increased revenues in December 2022 compared to December 2021. Materials and supplies inventories were higher due to increased prices for certain inventory items because of inflation, higher demands, and/or product shortages as well as increased inventory levels for certain items for planned work activities. Nuclear fuel was higher due to uranium purchases and related inventory costs. The net OPEB asset was higher due to an increase in the fiduciary net position because of favorable market conditions in 2021.

Deferred Outflows in 2022 increased $123.3 million or 82.5% over 2021, due primarily to an increase in deferred outflows for asset retirement obligations for the Cooper Nuclear Station because of the inflation adjustment to the related asset retirement obligation and the lower investment balances to fund these obligations. This increase in Deferred Outflows was partially offset by a decrease in the deferred outflows for OPEB from lower employer contributions in 2022.

Total Liabilities, Deferred Inflows and Net Position

Total Liabilities in 2023 decreased $77.1 million or 3.5% from 2022, due primarily to lower balances for debt and asset retirement obligations. Debt balances were lower because of principal payments and premium amortization. Asset retirement obligations were lower due to an updated study for Cooper Nuclear Station.

Deferred Inflows in 2023 increased $89.1 million or 15.6% over 2022, due primarily to increases in regulatory liabilities, including the authorization of a $69.3 million regulatory liability for Cooper Nuclear Station costs in 2023. The increase in Deferred Outflows was partially offset by a net reduction in rate stabilization fund balances or unearned revenues.

Net Position in 2023 decreased $28.9 million from 2022. The reasons for this change are disclosed in the analysis section for the Statements of Revenues, Expenses and Changes in Net Position.

Total Liabilities in 2022 decreased $71.4 million or 3.1% from 2021, due primarily to lower balances for debt because of principal payments and premium amortization. The decrease in Total liabilities was partially offset by an increase in asset retirement obligations due to inflation adjustments.

Deferred Inflows in 2022 decreased $9.5 million or 1.6% from 2021, due primarily to a decrease in the regulatory liability for outage collections for Cooper Nuclear Station, which was partially offset by increases in other regulatory liabilities.

Net Position in 2022 decreased $52.1 million from 2021. The reasons for this change are disclosed in the analysis section for the Statements of Revenues, Expenses and Changes in Net Position.

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

For the years ended December 31,	2023	2022	2021
Operating Revenues	$ 1,071,924	$ 1,196,972	$ 1,221,778
Operating Expenses	(1,034,664)	(1,079,904)	(1,064,354)
Operating Income	37,260	117,068	157,424
Investment and Other Income (Loss)	45,657	(10,194)	14,608
Debt and Related Expenses	(30,792)	(25,913)	(38,969)
Change in Net Position	$ 52,125	$ 80,961	$ 133,063

SOURCES OF OPERATING REVENUES (in 000's)

For the years ended December 31,	2023	2022	2021
Firm Retail and Wholesale Sales	$ 842,737	$ 819,768	$ 783,675
Participation and Capacity Sales	67,399	86,006	66,702
Other Sales	178,701	197,395	386,641
Other Operating Revenues	68,537	72,465	72,267
Unearned Revenues	(85,450)	21,338	(87,507)
Total Operating Revenues	$ 1,071,924	$ 1,196,972	$ 1,221,778

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. 2023 marked the tenth consecutive year with no overall retail base rate increases and the sixth consecutive year with no wholesale base rate increases. There were no overall base rate increases for retail or wholesale customers yet again in 2024.

The 2016 Contracts provide for cost-based rates and allow the District to retain surplus net revenues and collect for deficit net revenues, up to defined limits, in a rate stabilization account. The initial limit on surplus net revenues that can be accumulated in the rate stabilization account is an amount equivalent to 10.0% of annual production revenues derived from all 2016 Contracts. Such limit can be increased by the Board to 20.0% of annual production revenues. The initial limit on deficit net revenues that can be accumulated in the rate stabilization account is an amount equivalent to 5.0% of annual production revenues derived from all 2016 Contracts. Any surplus accumulation in excess of 20.0% of annual production revenues requires approval of a majority of members of the Rate Review Committee that is established pursuant to the 2016 Contracts. 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. The provision for establishing a new/replacement generation fund has never been exercised.

The District implemented a 12-month PCA rate to refund amounts to its wholesale customers for production rate stabilization funds in excess of the 10.0% accumulated limit. The refunds amounted to $56.8 million, $33.9 million, $74.2 million, and $73.2 million for 12-month periods beginning January 1, 2024, February 1, 2023, February 1, 2022, and February 1, 2021, respectively. The PCA equated to a one-year average bill reduction for wholesale customers compared to base rates of 7.2%, 4.4% and 10.1%, respectively. The PCA also resulted in an average annual decrease for retail customers of 1.0%, 2.2% and 3.9% compared to base rates for the respective 12-month periods. 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 $23.0 million, or 2.8%, from $819.8 million in 2022 to $842.7 million in 2023. The increase was due primarily to a lower PCA rate for refunds in 2023. Revenues from firm sales increased $36.1 million, or 4.6%, from $783.7 million in 2021 to $819.8 million in 2022. The increase was due primarily to higher retail industrial energy sales and a weather-related increase in other retail and wholesale energy sales.

Revenues from Participation and Capacity Sales

Revenues from participation sales decreased from $86.0 million in 2022 to $67.4 million in 2023, a decrease of $18.6 million, or 21.6%. The decrease was due primarily to reduced revenues for capacity sales and wind facilities. Revenues from participation sales increased from $66.7 million in 2021 to $86.0 million in 2022, an increase of $19.3 million, or 28.9%. The increase was due primarily to additional capacity sales, including capacity sales from a 2022 agreement, which expired on December 31, 2022.

Revenues from Other Sales

Other sales consist of sales in SPP's Integrated Market and nonfirm sales to other utilities. Other sales decreased from $197.4 million in 2022 to $178.7 million in 2023, a decrease of $18.7 million, or 9.5%. Although energy sales were higher, the decrease was due primarily to lower average prices due to lower natural gas prices and higher wind generation in the SPP Integrated Market. Other sales decreased from $386.6 million in 2021 to $197.4 million in 2022, a decrease of $189.2 million, or 48.9%. The decrease was due primarily to the February 2021 extreme weather event and also generating station outages in 2022, including the planned refueling and maintenance outage at the Cooper Nuclear Station.

Other Operating Revenues

Other operating revenues consist primarily of revenues from transmission and other miscellaneous revenues. These revenues were $68.5 million, $72.5 million, and $72.3 million in 2023, 2022 and 2021, respectively. The majority of these revenues consist of those received from other SPP transmission customers. The decrease in revenues in 2023 from 2022 was due primarily to the reduction in SPP revenues received from other transmission customers as a result of the expiration of the Balanced Portfolio Transfer initiative related to Base Plan Funded projects that occurred over a 10-year period from October 2012 through September 2022.

Unearned Revenues

Under the provisions of the 2016 Contracts, any surplus or deficiency between net revenues and revenue requirements, within certain limits set forth in the 2016 Contracts, may be adjusted in the rate stabilization account. Any amounts in excess of the rate stabilization accumulation 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.

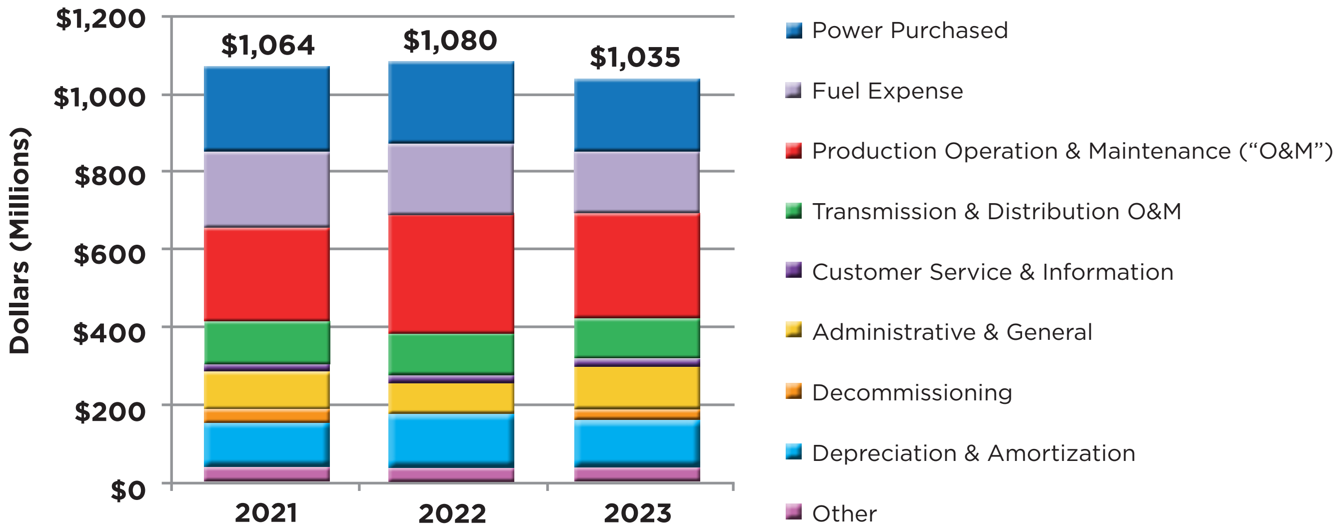
The following table shows the increase (decrease) in revenues from rate stabilization and other regulatory accounts for the years 2023, 2022 and 2021, respectively (in 000's).

	2023	2022	2021
Surplus revenues deferred to future periods	$ (67,007)	$ (73,822)	$ (144,556)
Refunded revenues from prior periods	76,453	74,160	78,049
Cooper Nuclear Station outage collections	(25,550)	21,000	(21,000)
Cooper Nuclear Station reserve	(69,346)	-	-
	$ (85,450)	$ 21,338	$ (87,507)

The balance of the regulatory liability for unearned revenues to be applied as credits against revenue requirements in future rate periods was $258.3 million, $267.8 million, and $268.1 million, as of December 31, 2023, 2022 and 2021, respectively.

Operating Expenses

The following chart illustrates operating expenses for the years ended December 31, 2021 through 2023.



Total operating expenses in 2023 were $1,034.7 million, a decrease of $45.2 million from 2022. Total operating expenses in 2022 were $1,079.9 million, an increase of $15.6 million over 2021. The changes were due primarily to the following:

Power purchased expenses were $179.2 million, $216.9 million and $219.9 million in 2023, 2022 and 2021, respectively. These expenses decreased $37.7 million in 2023 from 2022 due primarily to reduced quantities and prices for purchases in SPP Integrated Market and lower costs for wind agreements, which were partially offset by higher costs for purchases under agreements for NC2, Western and Loup. Power purchased expenses decreased $3.0 million in 2022 from 2021 due primarily to lower costs in 2022 from the SPP Integrated Market and hydro purchases, which were partially offset by higher costs for wind agreements.

Fuel expenses were $161.5 million, $175.4 million and $198.7 million in 2023, 2022 and 2021, respectively. These expenses decreased $13.9 million in 2023 from 2022 due primarily to lower costs for the Beatrice, Sheldon, and Canaday Stations, which were partially offset by higher costs for the Cooper Nuclear and Gerald Gentleman Stations. The lower costs for Beatrice and Canaday Stations were due primarily to lower fuel prices as generation was higher in 2023 than 2022. The lower costs for Sheldon Station were due primarily to lower generation. The higher costs for the Cooper Nuclear and Gerald Gentleman Stations were due primarily to higher generation. Fuel expenses decreased $23.3 million in 2022 from 2021 due primarily to lower costs for the Cooper Nuclear, Beatrice and Canaday Stations, which were partially offset by higher costs for the Gerald Gentleman and Sheldon Stations. The lower costs for the Beatrice and Canaday Stations in 2022 were because of higher costs in 2021 related to the February extreme weather event. The lower costs for the Cooper Nuclear Station were because of the 2022 planned refueling and maintenance outage.

Production operation and maintenance expenses were $275.4 million, $300.3 million and $230.1 million in 2023, 2022 and 2021, respectively. These expenses decreased $24.9 million in 2023 from 2022 due primarily to the planned refueling and maintenance outage at Cooper Nuclear Station in 2022. These expenses increased $70.2 million in 2022 over 2021 due primarily to the planned refueling and maintenance outage at Cooper Nuclear Station, outage maintenance at Gerald Gentleman Station, and higher net expenses from TEA.

Transmission and distribution operation and maintenance expenses were $119.8 million, $116.0 million and $112.3 million in 2023, 2022 and 2021, respectively. These costs increased $3.8 million in 2023 over 2022 due primarily to increased costs for salaries and benefits, outside services, and materials and supplies. Transmission and distribution operation and maintenance expenses increased $3.7 million in 2022 from 2021 due primarily to increased costs for SPP expenses, outside services and fleet expenses.

Customer service and information expenses were $18.6 million, $16.8 million and $15.6 million in 2023, 2022 and 2021, respectively.

Administrative and general expenses were $91.1 million, $83.2 million and $100.8 million in 2023, 2022 and 2021, respectively. These expenses increased $7.9 million in 2023 over 2022 due primarily to an increase in salaries and property insurance. These expenses decreased $17.6 million in 2022 from 2021 due primarily to a reduction in OPEB expenses.

Payments to retail communities were $32.4 million, $32.6 million and $30.1 million in 2023, 2022 and 2021, respectively. These payments were collected from retail customers in communities with PRO Agreements and remitted to the communities. These payments increased $2.5 million in 2022 over 2021 due primarily to higher retail sales revenues and an increase in the percentage of revenues collected for certain communities.

Decommissioning expenses were $18.1 million, $0.0, and $25.2 million in 2023, 2022 and 2021, 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 for non-nuclear assets and Cooper Nuclear Station were $16.3 million and $1.8 million, respectively, in 2023. Decommissioning expenses were $0.0 in 2022 because investment losses due to adverse market conditions offset rate collections for the decommissioning of non-nuclear assets.

Depreciation and amortization expenses were $128.4 million, $128.8 million, and $121.8 million in 2023, 2022 and 2021, respectively. The increase of $7.0 million from 2021 to 2022 was due primarily to the amortization of the regulatory asset for OPEB as rate collections began in 2022 for debt service on the debt used to partially fund the OPEB Trust and an increase in depreciation expense for the Ainsworth Wind Facility. These increases were partially offset by lower depreciation expense for Gerald Gentleman Station and lower amortization costs related to assets of retail customers.

Payments in lieu of taxes were $10.2 million, $10.2 million, and $9.9 million in 2023, 2022 and 2021, respectively. The District makes payments in lieu of taxes to local political subdivisions as required by the Nebraska Constitution.

Investment and Other Income (Loss)

Investment and other income (loss) were $45.7 million, ($10.2) million and $14.6 million in 2023, 2022 and 2021, respectively. The increase of $55.9 million in 2023 over 2022 was due primarily to favorable market returns in 2023 and unfavorable market returns in 2022. The decrease of $24.8 million in 2022 from 2021 was due primarily to unfavorable market returns in 2022 and favorable market returns in 2021.

Debt and Related Expenses

Debt and related expenses were $30.8 million, $25.9 million, and $39.0 million in 2023, 2022 and 2021, respectively. The increase of $4.9 million in 2023 over 2022 was due primarily to a decrease in bond premium amortization and higher interest expense on revolving credit agreements because of higher interest rates. The decrease of $13.1 million in 2022 from 2021 was due primarily to lower interest expense on revenue bonds and an increase in bond amortization, which was partially offset by higher interest expense on revolving credit agreements because of higher interest rates.

Change in Net Position

The change in net position was $52.1 million, $81.0 million, and $133.1 million in 2023, 2022 and 2021, respectively. The change in net position in 2023 decreased $28.9 million from 2022 due primarily to a reduction in revenues to establish a $69.3 million regulatory liability for Cooper Nuclear Station costs, including costs for debt retirement or unrecovered nuclear fuel costs in inventory or in the core. Other decreases in changes in net position in 2023 from 2022 were due to lower bond premium amortization and capitalized interest. These decreases in changes in net position were partially offset by investment gains due to improved market conditions, higher amounts for allowances for funds used for construction, and higher rate collections for principal payments and construction from revenue. The change in net position in 2022 decreased $52.1 million from 2021 due primarily to lower rate collections for principal payments for debt service and construction from revenue, amortization of the regulatory asset for OPEB, and investment losses due to adverse market conditions, which were partially offset by higher bond premium amortization.

CONDENSED STATEMENTS OF CASH FLOWS (in 000's)

For the years ended December 31,	2023	2022	2021
Net Cash Provided by Operating Activities	$ 289,851	$ 227,742	$ 419,907
Net Cash Provided by (Used in) Investing Activities	(80,580)	93,257	(94,413)
Net Cash Used in Capital and Financing Activities	(214,399)	(336,659)	(314,472)
Net Increase (Decrease) in Cash and Cash Equivalents	(5,128)	(15,660)	11,022
Cash and Cash Equivalents, Beginning of Year	19,129	34,789	23,767
Cash and Cash Equivalents, End of Year	$ 14,001	$ 19,129	$ 34,789

The increase in net cash provided by operating activities in 2023 from 2022 was because of higher receipts from customers. The decrease in net cash provided by investing activities was due to a net purchase position in 2023 compared to a net sell/maturity position in 2022. The decrease in net cash used in capital and financing activities was primarily due to lower capital expenditures, increased contributions in aid of construction, and the issuance of General Revenue Bonds, 2023 Series A. The decrease in net cash provided by operating activities in 2022 from 2021 was because of larger cash inflows in 2021 due primarily to the higher net revenues related to the February 2021 extreme weather event. The increase in cash used for capital and related financing activities in 2022 over 2021 was due primarily to purchases of nuclear fuel inventory. The increase in net cash provided by operating activities in 2021 was due primarily to SPP financial transactions, most of which were related to the February extreme weather event.

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. Debt service coverage ratios were 1.62, 2.31 and 2.71 in 2023, 2022 and 2021, respectively. The debt service coverage was lower in 2023 than 2022 due primarily to a decrease in net revenues to establish a $69.3 million regulatory liability for Cooper Nuclear Station costs. The decrease in the 2022 debt service coverage ratio over 2021 was due primarily to a decrease in net revenues. Net revenues were higher in 2021 due primarily to the recognition of surplus revenues from the February 2021 weather event for additional debt principal payments on the revolving credit agreements. 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. Debt service for 2022 included the General Revenue Bonds, 2012 Series B, redeemed in December 2022. If the debt service on the said General Revenue Bonds so redeemed were excluded for 2022, the debt service coverage was 2.76 times for 2022. For additional detail, refer to the Calculation of Debt Service Ratios in the Supplementary Information.

FINANCING ACTIVITIES

Good bond 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 bond ratings on its General Revenue Bonds were as follows:		
Fitch Ratings	A+	(stable outlook)
Moody's Investors Service	A1	(stable outlook)
S&P Global 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, transmission and retail 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 Wholesale Power 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 Wholesale Power Contracts. The District's transmission indebtedness is payable from the revenues received during the term of the Wholesale Power 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 will issue additional debt in 2024 to finance capital costs for its capital improvement plan. Debt may be financed using General Revenue Bonds, tax-exempt and taxable revolving credit agreements ("TERCA" and "TRCA"), or other financing options. Details of the District's debt balances and activity are included in Note 7. Debt, in the Notes to Financial Statements.

CAPITAL REQUIREMENTS

The Board-approved capital projects totaled approximately $105.8 million, $94.4 million, and $163.4 million in 2023, 2022 and 2021, respectively. The amounts approved for capital projects in a year do not always agree to the total project costs as the approvals for some capital projects occur in more than one year. The District's capital requirements are funded with monies generated from operations, debt proceeds and other available reserve funds.

Significant capital projects for 2023 included:

- $9.3 million for Columbus East 115 transformer upgrade
- $8.9 million for Gerald Gentleman Station Unit 2 boiler tube surface replacement
- $5.6 million for Sheldon Station condenser and dewatering bins replacement/upgrade
- $5.5 million for Cooper Nuclear Station 316(b) environmental modifications
- $5.0 million for Cooper Nuclear Station reactor feed pump turbine B overhaul
- $4.9 million for Sheldon Station 423 effluent compliance project
- $4.7 million for 345kV and 115kV line and substation upgrades
- $4.4 million for technical software upgrades to payroll, time and attendance, and medical leave management
- $2.6 million for Beatrice Power Station upgrades

Significant capital projects for 2022 included:

- $9.2 million for transmission line breaker and relay replacements
- $7.2 million for Gerald Gentleman Station 316(b) environmental modifications
- $7.0 million for Cooper Nuclear Station condenser internal large bore piping replacement
- $6.4 million for Supervisory Control and Data Acquisition and Outage Management System integrated technology solution implementation/upgrade
- $5.3 million for 345kV and 115kV line and substation upgrades
- $4.9 million for April and June 2022 storm damage
- $3.6 million for Firth substation and capacitor bank, an SPP Notification to Construct ("NTC") Project

Significant capital projects for 2021 included:

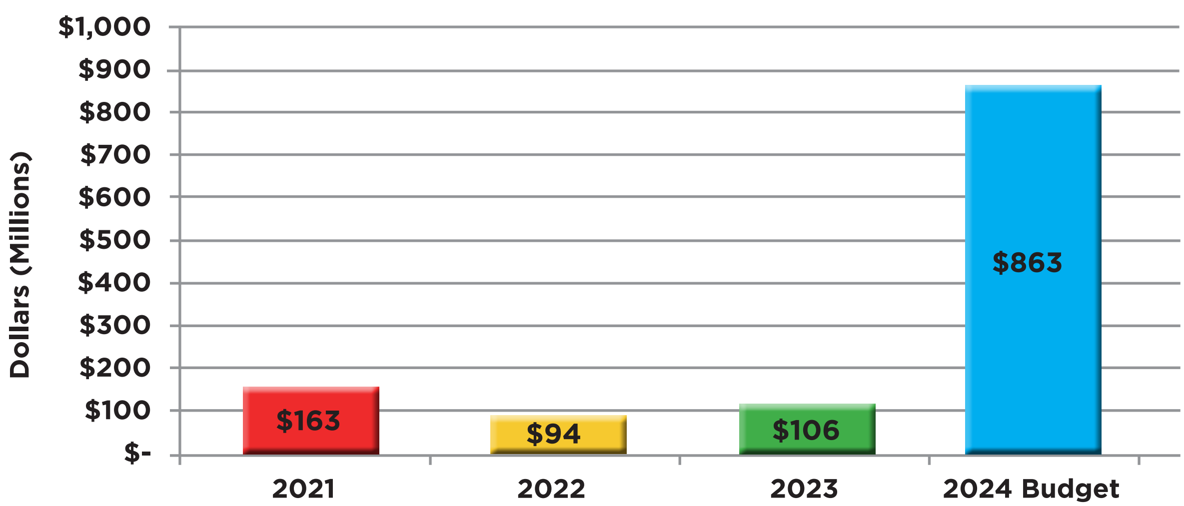
- $70.4 million for 345kV and 115kV line and substation additions and upgrades
- $14.5 million for SAP S/4HANA and SAP Analytics Cloud Planning technical software upgrades and advancements
- $7.8 million for Cooper Nuclear Station 316(b) environmental modifications
- $4.9 million for North Platte Hydro 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

There were other authorized capital projects for renewals and replacements to existing facilities and other additions and improvements of $61.9 million, $50.8 million, and $49.8 million for 2023, 2022 and 2021, respectively.

The Board-approved budget for capital projects for 2024 is $862.9 million. Specific capital projects for 2024 include:

- $230.0 million for RICE and generator step-up transformers
- $224.0 million for CTs and generator step-up transformers
- $117.8 million for battery energy storage system near Ainsworth Wind Energy Facility
- $56.4 million for Cooper Nuclear Station license renewal project
- $25.0 million for transformer purchases
- $20.1 million for Scottsbluff-Victory Hill 115 kV project
- $19.0 million for Gothenburg industrial 115 kV substation project
- $15.0 million for Cooper Nuclear Station spare main generator rotor
- $12.8 million for Kearney Tech1 Tower 115 kV project
- $10.6 million for Etna 345 kV substation transformer

The following chart illustrates the Board-approved capital projects for the years ended December 31, 2021 through 2023, including the Board-approved budget for the year ended December 31, 2024.



TRANSMISSION LINE PROJECTS

The District received an SPP NTC 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 226 miles of 345 kV transmission line from Gerald Gentleman Station, north to a substation east of Thedford, then eastward to an existing 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*.

The District has accepted SPP NTC for two new 115 kV transmission lines and associated substation terminal modifications. The Kearney 115 kV transmission line extends from the TechOne substation to the Tower substation in Kearney, Nebraska and is approximately 9 miles in length. The second 115 kV transmission line, which is in the Scottsbluff area and extends from the Scottsbluff substation to the Victory Hill substation, is approximately 10 miles long. Both projects are being built to support local load growth and to relieve congestion on the transmission system. The projects are currently in the design, material procurement and easement acquisition phase with construction activities planned to begin in November 2024 with an in-service date for both projects of May 2025. The expected combined cost for both projects is $38.5 million. The projects will be base plan funded in accordance with the SPP Tariff. The Annual Transmission Revenue Requirement will be determined in accordance with the SPP Tariff and allocated 1/3 to the SPP Region and 2/3 to the District's Transmission Pricing Zone. The District expects to recover approximately $15.9 million of these NTC costs from other SPP members. The balance of $22.6 million will be recovered through the District's transmission rates.

The District has accepted SPP NTC for a new 115 kV transmission line with associated substation terminal modifications and a 230/115 kV transformer upgrade. The 115 kV transmission line extends from the Norfolk substation to the Stanton North substation northeast of Stanton, Nebraska and is approximately 8 miles in length. The transformer upgrade is located at the Hoskins substation northeast of Norfolk. The network upgrades are being built to increase the system's transmission capacity to meet increasing demand and further enhance reliability and resiliency in the Stanton, Cuming and Burt County areas. The projects are currently in the design and material procurement phase with construction activities planned to begin in November 2024 for the substation projects and the summer of 2025 for the transmission line with an in-service date for both projects of November 2026. The expected combined cost for both projects is $26.0 million. The projects will be base plan funded in accordance with the SPP Tariff. The Annual Transmission Revenue Requirement will be determined in accordance with the SPP Tariff and allocated 1/3 to the SPP Region and 2/3 to the District's Transmission Pricing Zone. The District expects to recover approximately $10.7 million of these NTC costs from other SPP members. The balance of $15.3 million will be recovered through the District's transmission rates.

MONOLITH, INC.

Monolith, 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 1 facility, which became fully operational in 2020. Monolith plans to expand the facility, Phase 2, to produce carbon black and hydrogen. They propose fabricating "green" ammonia with their hydrogen. Monolith is interested in renewable energy and Renewable Energy Credits ("REC") for its facilities. 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 NTC from SPP for some of the transmission facilities required for the expansion.

MEADOWLARK PROJECT

A Nebraska-based corporation plans to build and operate a liquid fertilizer production facility in Gothenburg, Nebraska. This facility is expected to achieve net negative emissions through a zero-carbon production process. The project has been named the Meadowlark Project. The facility will be a retail industrial customer of the City of Gothenburg, a firm wholesale customer of the District. The District is in the early planning stages for the load connection in the Gothenburg area. The District has begun preliminary line routing activities and anticipates receiving a NTC from SPP in 2024. The Meadowlark project will require construction of 4 new 115 kV transmission lines and the rebuild of an existing 115 kV transmission line. In addition, the project will also require the construction of a short section of 345 kV transmission line. The proposed schedule is to have the final line route announcement be made around first quarter of 2025.

SUPPLY CHAIN DISRUPTION ISSUES

The District, like other electric utilities, experienced supply chain disruption issues at the end of 2021 which have continued for certain materials and supplies. These issues have been attributed to high demand and adverse impacts on production outputs related to insufficient raw material and labor. As a result, delays and increased cost impacts may be experienced in completing certain projects and work activities.

INFRASTRUCTURE INVESTMENT AND JOBS ACT (“IIJA”) AND INFLATION REDUCTION ACT (“IRA”)

The IRA and the IIJA allow not-for-profit public power utilities like the District to potentially receive federal payments for a variety of generation and infrastructure projects. Opportunities are being pursued which align with the District’s strategic priorities. Multiple statutory provisions are subject to the issuance of pending regulatory guidance. At this time, the District has not been awarded any substantial grant programs; however, opportunities continue to be monitored and reviewed for application.

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 61.9% and 50.2% for 2023 and 2022, respectively. The District’s most recent IRP was approved by the Board in September 2023. The IRP evaluated a 30-year time period, taking into consideration the District goal, approved by the Board in 2021, of net zero carbon emissions from the District’s generation sources by 2050, while maintaining affordability, reliability and system resiliency. Major variables included CO_2, load and market uncertainty.

Recommendations from the IRP included:

- Start proceeding with the second relicense renewal process at Cooper Nuclear Station, as well as further refine the capital costs needed for the relicense. Monitor Cooper Nuclear Station operating costs and reevaluate relicensing if projected costs are significantly higher than assumptions in the IRP.
- Continue to operate Gerald Gentleman Station on coal, while monitoring potential risks to continued operation. The District should also continue to investigate carbon capture & sequestration (“CCS”) for potentially lower cost options and impacts from IRA credits, as well as other options for the site in the event of a low carbon future.
- Continue to pursue required modifications at Sheldon Station for compliance with Effluent Limitation Guidelines (“ELG”) rule requirements, while also investigating potential restoration of the site to natural gas operation. The District should also obtain better estimates for natural gas restoration vs. a dual-fuel combustion turbine or RICE facility before making a final decision on any modifications.
- Continue to monitor small modular reactor (“SMR”) progress and complete preliminary siting studies.
- Evaluate the potential for increased funding of the EnergyWise℠ program, in order to facilitate further discussion with our customers regarding the most mutually advantageous level of energy efficiency for the District to pursue in the future.
- Work with customers to identify mutually beneficial opportunities to increase the District’s use of Demand Response (“DR”). The District should also continue to participate in on-going review of SPP’s requirements for DR to ensure its existing programs remain compliant and continue to provide a resource adequacy benefit.
- Explore the possibility of renewable installation utilizing IRA credits. The exact size and type and the value will depend on what is available to interconnect to the transmission system within a few years.
- Investigate resource options due to the higher near-term projected loads.

ENERGY MARKET 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 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 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 Market Risk Management (“EMRM”) program. The program originates with the Board-approved EMRM Governing Policy and the EMRM-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 EMRM program. The objective of the EMRM 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 EMRM 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.

CYBER AND PHYSICAL SECURITY

The District has physical security protections for its critical assets and dedicated teams who are constantly monitoring for any potential physical or cyber threats that may be aimed towards the electric industry and the District. Programs, tools, and on-going assessments are in place that help identify and defend against threats, exercise response plans, and increase education and awareness of employees. Industry best practice frameworks are followed which focus on continuous improvement to increase the overall security posture of the District. In addition, the District has continued to purchase cyber security insurance coverage to provide additional protections from operational and financial risks due to cyber security incidents. In the event of an incident, the insurance would help to mitigate costs from damages incurred due to a cyber breach, as well as fines assessed from non-compliance of requisite data security standards.

ECONOMIC FACTORS

The estimated gross state product increased by 5.5% between the third quarter of 2022 and the third quarter of 2023, according to the report, “State Gross Domestic Product”, issued by the Bureau of Economic Analysis (“Bureau”). The report also showed that the US economy experienced a 2.9% increase in real national gross domestic product over the same 12-month period.

According to the Bureau, Nebraska experienced declines in “Educational Services” (-4.0%), “Finance and Insurance” (-2.7%), “Other Services” (-2.7%), and “Accommodations and Food Services” (-0.4%) sectors. These declines were offset by increases in “Agriculture, Forestry, and Fishing” (63.4%), “Mining, Quarrying, and Oil and Gas Extraction” (13.2%), “Retail Trade” (9.3%), and “Management of Companies and Enterprises” (6.4%).

Despite strong demand for goods and services in 2023, supply constraints lead to higher prices and lost production. These constraints included lack of inputs, due to supply chain disruptions and labor shortages. There was upward pressure on wages due to a lower labor force participation rate. This upward pressure led to higher rates of inflation in 2023. According to the Consumer Price Index for All Urban Consumers (“CPI-U”), the average annual inflation rate was 4.1% for 2023 and monthly inflation rates were 3.4% and 3.1% for December 2023 and January 2024, respectively.

Nebraska and the Midwest region continue to experience unemployment rates below the national average, according to information from the Bureau of Labor Statistics for Nebraska and the US. Nebraska’s average annual unemployment rate increased from the 2022 value of 2.2% to 2.3% in 2023. This rate was well below the 2023 national average unemployment rate of 3.6%. Nebraska’s preliminary, seasonally adjusted unemployment rate was 2.5% in December 2023, up from the revised 2.2% in December 2022. Both numbers were well below the national December seasonally adjusted unemployment rates of 3.7% and 3.5% in 2023 and 2022, respectively. Nebraska’s revised December 2023 unemployment rate was the fifth lowest in the nation. The District continues to monitor changes in national and global economic conditions, which could impact the cost of debt and access to capital markets.

CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY AND THE NATION

The Electric Utility Industry in General

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

- changes in resource mix,
- adequacy of generation resources and transmission capacity,
- significant potential load growth and/or other changes in future load requirements,
- 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,
- increases in costs,
- shifts in the availability and relative costs of different fuels,
- risks 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, 2023 and 2022, 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 respective financial position of the business-type activities and the fiduciary activities of Nebraska Public Power District as of December 31, 2023 and 2022, and the respective changes in financial position and, where applicable, cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America.

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 *required supplementary information* on pages 7 through 24 and 62 through 63 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 review* and *supplementary information* on pages 6 and 64, 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 11, 2024

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

As of December 31, (in 000's)	2023	2022
ASSETS AND DEFERRED OUTFLOWS		
Current Assets:		
Cash and cash equivalents	$ 14,001	$ 19,129
Investments	717,284	619,878
Receivables, less allowance for doubtful accounts of $301 and $532, respectively	112,617	136,906
Fossil fuels, at average cost	42,945	34,496
Materials and supplies, at average cost	145,412	129,851
Prepayments and other current assets	20,718	16,193
	1,052,977	956,453
Special Purpose Funds:		
Construction funds	12,767	15,148
Debt service and reserve funds	94,194	71,770
Employee benefit funds	4,154	3,048
Decommissioning funds	634,467	602,453
	745,582	692,419
Utility Plant, at Cost:		
Utility plant in service	5,334,121	5,255,397
Less reserve for depreciation	3,182,028	3,102,840
	2,152,093	2,152,557
Construction work in progress	260,755	260,841
Nuclear fuel, at amortized cost	138,957	146,898
	2,551,805	2,560,296
Other Long-Term Assets:		
Regulatory asset for other postemployment benefits	17,829	41,829
Long-term capacity contracts	110,718	118,105
Unamortized financing costs	4,537	5,087
Investment in The Energy Authority	27,885	26,182
Net other postemployment benefit asset	18,103	82,038
Other	10,927	5,071
	189,999	278,312
Total Assets	4,540,363	4,487,480
Deferred Outflows of Resources:		
Asset retirement obligation	193,670	243,014
Unamortized cost of refunded debt	2,622	2,457
Other postemployment benefits	87,775	27,415
	284,067	272,886
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 4,824,430	$ 4,760,366

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

As of December 31, (in 000's)	2023	2022
LIABILITIES, DEFERRED INFLOWS, AND NET POSITION		
Current Liabilities:		
Revenue bonds, current	$ 65,110	$ 105,125
Revolving credit agreements, current	109,735	-
Accounts payable and accrued liabilities	73,799	78,385
Accrued in lieu of tax payments	10,147	10,175
Accrued payments to retail communities	2,464	2,638
Accrued compensated absences	22,756	21,330
Other	20,577	20,539
	304,588	238,192
Long-Term Debt:		
Revenue bonds, net of current	921,774	965,517
Revolving credit agreements, net of current	38,035	148,732
	959,809	1,114,249
Other Long-Term Liabilities:		
Asset retirement obligation	836,937	851,819
Other	42,014	16,200
	878,951	868,019
Total Liabilities	2,143,348	2,220,460
Deferred Inflows of Resources:		
Unearned revenues	258,311	267,758
Other deferred inflows	402,405	303,907
	660,716	571,665
Net Position:		
Net investment in capital assets	1,569,236	1,496,941
Restricted	21,866	21,860
Unrestricted	429,264	449,440
	2,020,366	1,968,241
TOTAL LIABILITIES, DEFERRED INFLOWS, AND NET POSITION	$ 4,824,430	$ 4,760,366

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)	2023	2022
Operating Revenues	$ 1,071,924	$ 1,196,972
Operating Expenses:		
Power purchased	179,175	216,946
Production:		
Fuel	161,478	175,432
Operation and maintenance	275,381	300,347
Transmission and distribution operation and maintenance	119,759	115,968
Customer service and information	18,628	16,837
Administrative and general	91,123	83,239
Payments to retail communities	32,407	32,594
Decommissioning	18,149	(479)
Depreciation and amortization	128,373	128,803
Payments in lieu of taxes	10,191	10,217
	1,034,664	1,079,904
Operating Income	37,260	117,068
Investment and Other Income:		
Investment income (loss)	43,529	(12,371)
Other income	2,128	2,177
	45,657	(10,194)
Change in Net Position Before Debt and Other Expenses	82,917	106,874
Debt and Related Expenses:		
Interest on revenue bonds	44,042	44,627
Allowance for funds used during construction	(7,780)	(2,428)
Bond premium amortization net of debt issuance expense	(12,830)	(19,264)
Interest on revolving credit agreements	7,360	2,978
	30,792	25,913
Change in Net Position	52,125	80,961
Net Position:		
Beginning balance	1,968,241	1,887,280
Ending balance	$ 2,020,366	$ 1,968,241

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)	2023	2022
Cash Flows from Operating Activities:		
Receipts from customers and others	$ 1,134,631	$ 1,098,405
Other receipts	356	188
Payments to suppliers and vendors	(535,053)	(577,388)
Payments to employees	(310,083)	(293,463)
Net cash provided by operating activities	289,851	227,742
Cash Flows from Investing Activities:		
Proceeds from sales and maturities of investments	3,229,348	3,905,350
Purchases of investments	(3,319,214)	(3,802,462)
Income received on investments	9,432	(10,012)
Change in cash held in special purpose funds	(146)	381
Net cash provided by (used in) investing activities	(80,580)	93,257
Cash Flows from Capital and Related Financing Activities:		
Proceeds from issuance of revenue bonds	161,424	-
Proceeds from revolving credit agreements	42,937	55,068
Capital expenditures for utility plant	(135,610)	(193,938)
Contributions in aid of construction and other reimbursements	41,007	4,967
Principal payments on revenue bonds	(230,950)	(95,155)
Interest payments on revenue bonds	(44,042)	(44,627)
Interest paid on defeased revenue bonds	(1,017)	-
Principal payments on revolving credit agreements	(43,899)	(66,129)
Interest payments on revolving credit agreements	(7,199)	(2,585)
Other non-operating revenues	2,950	5,740
Net cash used in capital and related financing activities	(214,399)	(336,659)
Net increase (decrease) in cash and cash equivalents	(5,128)	(15,660)
Cash and cash equivalents, beginning of year	19,129	34,789
Cash and cash equivalents, end of year	$ 14,001	$ 19,129

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

For the years ended December 31, (in 000's)	2023	2022
Reconciliation of Operating Income to Cash Provided By Operating Activities:		
Operating income	$ 37,260	$ 117,068
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation and amortization	128,373	128,803
Undistributed net revenue - The Energy Authority	430	(38)
Decommissioning, net of customer contributions	4,366	(12,778)
Amortization of nuclear fuel	33,026	29,020
Changes in assets and liabilities which provided (used) cash:		
Receivables, net	(23,064)	(22,738)
Fossil fuels	(8,449)	(2,679)
Materials and supplies	(15,561)	(9,021)
Prepayments and other current assets	(6,934)	(795)
Accounts payable and accrued payments to retail communities	(2,361)	6,684
Unearned revenues	(9,447)	(338)
Other deferred inflows	116,624	(7,353)
Other liabilities	35,588	1,907
Net cash provided by operating activities	$ 289,851	$ 227,742

	2023	2022
Supplementary Non-Cash Capital Activities:		
Change in utility plant additions in accounts payable	$ (1,930)	$ (551)

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)

	2023	2022
Assets:		
Cash and cash equivalents	$ 9,743	$ 3,218
Receivables:		
Investment income	792	716
Investments	347,681	322,342
Total Assets	358,216	326,276
Liabilities:		
Payables:		
Benefits - healthcare	108	144
Benefits - life insurance	60	74
Investment expense	126	31
Professional, administrative and other expenses	25	117
Total liabilities	319	366
Net Position - Restricted for Other Postemployment Benefits	$ 357,897	$ 325,910

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)	2023	2022
Additions:		
Contributions		
Employer	$ 2,850	$ 6,294
Investment Income (loss):		
Net appreciation (depreciation) in fair value of investments	41,457	(70,654)
Interest, dividends and other income	6,890	6,050
Total investment income (loss)	48,347	(64,604)
Less: Investment expenses	(1,052)	(1,043)
Net investment income (loss)	47,295	(65,647)
Total additions	50,145	(59,353)
Deductions:		
Health care benefits	17,757	16,598
Life insurance benefits	170	269
Professional, administrative and other expenses	231	212
Total deductions	18,158	17,079
Change in Net Position	31,987	(76,432)
Net Position - Restricted for Other Postemployment Benefits		
Beginning balance	325,910	402,342
Ending balance	$ 357,897	$ 325,910

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, 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 1.9% and 2.0% for the years ended December 31, 2023 and 2022. The District had fully depreciated utility plant, primarily related to Cooper Nuclear Station, which was still in service of $1,606.3 million and $1,579.5 million as of December 31, 2023 and 2022, 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 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 $8.1 million and $7.0 million in 2023 and 2022, respectively, which was included in depreciation and amortization expense. These utility plant additions, which were fully amortized, totaled $229.2 million and $222.2 million as of December 31, 2023 and 2022, 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 TERCA, or the 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 5.0%. For construction financed on a short-term basis, the rate was 4.5% and 1.0% for 2023 and 2022, respectively.

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 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 (i.e., rate stabilization funds) and other deferred inflows. 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 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 wholesale power supply contracts. Any surplus or deficit in revenues for retail service is accounted for in a similar manner.

The following table summarizes the balance of Unearned revenues as of December 31, 2023 and 2022 and activity for the years then ended (in 000's):

	2023	2022
Unearned revenues, beginning of year	$ 267,758	$ 268,096
Surpluses	67,006	73,822
Use of prior period rate stabilization funds in rates	(76,453)	(74,160)
Unearned revenues, end of year	$ 258,311	$ 267,758

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.

A regulatory liability for Cooper Nuclear Station costs, including costs for debt retirement or unrecovered nuclear fuel costs in inventory or in the core, was authorized by the Board for $69.3 million in 2023. The regulatory liability will be depleted and ultimately eliminated as revenues are recognized to cover specified nuclear costs as authorized in Board approved budgets prior to the conclusion of the decommissioning of the Station.

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 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 2023, the District collected approximately half of the costs of the 2024 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 2024, 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.

Other regulatory liabilities include the remaining balance of a sales tax refund for the construction of a renewable energy facility, the advanced collection of operations and maintenance expenses for an SPP-sponsored transmission upgrade and proceeds from the sale of Niobrara River water rights.

The following table summarizes the balance of Other deferred inflows of resources as of December 31, 2023 and 2022 (in 000's):

	2023	2022
Unrealized OPEB gains	$ 78,284	$ 93,964
DOE Settlements	78,312	78,312
Cooper Nuclear Station reserve	69,346	-
Non-nuclear decommissioning collections	65,660	51,808
Nuclear fuel disposal collections	57,103	50,643
Cooper Nuclear Station outage collections	25,550	-
Settlements for termination of agreements	21,725	26,093
Other regulatory liabilities	6,425	3,087
	$ 402,405	$ 303,907

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. 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") ceased to exist in 2023. This Statement addresses the accounting and financial effects that result from the replacement of interbank offered rates with other references rates. The District transitioned from LIBOR to the Securities Industry and Financial Markets Association ("SIFMA") as a reference rate on the TERCA on September 15, 2022. The District replaced LIBOR as a reference rate on the TRCA to the Secured Overnight Financing Rate ("SOFR") in 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 Board authorized the use of regulatory accounting to continue the revenue and expense recognition. for SBITA consistent with the rate methodology as used for the District's customers. The requirements of this Statement were implemented, using regulatory accounting, in 2023. There were no SBITA agreements deemed material for reporting under this new guidance as of December 31, 2023.

GASB Statement No. 101, *Compensated Absences,* was issued in June 2022. The District currently recognizes liabilities for unused vacation benefits earned by employees. This Statement requires the recognition of additional liabilities for certain compensated absences, like sick leave, regardless of whether the sick leave benefit is vested or not vested. Currently, there are not any liabilities for sick leave recognized on the District's financial statements as the sick leave benefits are not vested. This Statement will result in the recognition of additional liabilities on the District's financial statements for non-vested employee sick leave benefits. In December 2023, the Board authorized the use of regulatory accounting to continue the revenue and expense recognition for compensated absences consistent with the rate methodology as used for the District's customers. The District will implement the requirements of this Statement, using regulatory accounting, in 2024.

GASB Statement No. 102, *Certain Risk Disclosures,* was issued in December 2023. This Statement will require disclosures when certain concentrations or constraints and related events have occurred or have begun to occur that make a government vulnerable to a substantial impact. This information will provide users better information with which to understand and anticipate certain risks to a government's financial condition. The requirements of this Statement are effective for fiscal years beginning after June 15, 2024.

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 gain of $11.4 million in 2023 and an unrealized net loss $8.4 million in 2022, 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):

	2023		2022	
	Fair Value	Weighted Average Maturity (Years)	Fair Value	Weighted Average Maturity (Years)
U.S. Treasury and government agency securities ..	$ 1,007,808	4.7	$ 1,006,411	3.8
Corporate bonds	218,505	11	177,409	14.1
Municipal bonds	10,386	14	10,106	14.5
Cash and cash equivalents	240,168	0.0	137,500	0.0
Total cash and investments	$ 1,476,867		$ 1,331,426	
Portfolio weighted average maturity		4.9		4.8

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.

	2023	2022
Revenue funds - Cash and cash equivalents	$ 14,001	$ 19,129
Revenue funds - Cash equivalents in investments	197,765	107,059
Revenue funds - Investments	519,519	512,819
	$ 731,285	$ 639,007

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.

	2023	2022
Construction funds - Investments	12,767	15,148
	$ 12,767	$ 15,148

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 $22.0 million and $21.9 million as of December 31, 2023 and 2022, 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 $51.5 million and $49.9 million as of December 31, 2023 and 2022.

	2023	2022
Debt service and reserve funds - Cash and cash equivalents	$ 105	$ -
Debt service and reserve funds - Investments	94,089	71,770
	$ 94,194	$ 71,770

The Employee Benefit funds consist of a self-funded hospital-medical benefit plan for active employees only as of December 31, 2023 and 2022. The District pays 86% and 85% of the hospital-medical premiums with the employees paying the remaining 14% and 15% of the cost of such coverage for the years 2023 and 2022, respectively.

	2023	2022
Employee benefit funds - Cash and cash equivalents	$ 4,154	$ 3,048

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.

	2023	2022
Decommissioning funds - Cash and cash equivalents	$ 19,027	$ 8,264
Decommissioning funds - Investments	615,440	594,189
	$ 634,467	$ 602,453

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, 2023 and 2022.

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):

	2023			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 621,259	$ -	$ 621,259
Cash and cash equivalents	221,141	-	-	221,141
Decommissioning funds:				
U.S. Treasury and government agency securities	-	386,549	-	386,549
Corporate bonds	-	218,505	-	218,505
Municipal bonds	-	10,386	-	10,386
Cash and cash equivalents	19,027	-	-	19,027
	$ 240,168	$1,236,699	$ -	$ 1,476,867

	2022			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 599,737	$ -	$ 599,737
Cash and cash equivalents	129,236	-	-	129,236
Decommissioning funds:				
U.S. Treasury and government agency securities	-	406,674	-	406,674
Corporate bonds	-	177,409	-	177,409
Municipal bonds	-	10,106	-	10,106
Cash and cash equivalents	8,264	-	-	8,264
	$ 137,500	$1,193,926	$ -	$ 1,331,426

4. UTILITY PLANT:

Utility plant activity for the year ended December 31, 2023, was as follows (in 000's):

	December 31, 2022	Increases	Decreases	December 31, 2023
Nondepreciable utility plant:				
Land and improvements	$ 80,133	$ 4	$ -	$ 80,137
Construction in progress	260,841	101,065	(101,151)	260,755
Total nondepreciable utility plant	340,974	101,069	(101,151)	340,892
Nuclear fuel*	146,898	25,085	(33,026)	138,957
Depreciable utility plant:				
Generation - Fossil	1,708,905	30,973	(18,206)	1,721,672
Generation - Nuclear	1,369,234	6,900	(593)	1,375,541
Transmission	1,443,958	40,892	(3,372)	1,481,478
Distribution	267,679	19,144	(8,167)	278,656
General	385,488	17,501	(6,352)	396,637
Total depreciable utility plant	5,175,264	115,410	(36,690)	5,253,984
Less reserve for depreciation	(3,102,840)	(115,878)	36,690	(3,182,028)
Depreciable utility plant, net	2,072,424	(468)	-	2,071,956
Utility plant activity, net	$ 2,560,296	$ 125,686	$ (134,177)	$ 2,551,805

* Nuclear fuel decreases represented amortization of $33.0 million.

Utility plant activity for the year ended December 31, 2022, was as follows (in 000's):

	December 31, 2021	Increases	Decreases	December 31, 2022
Nondepreciable utility plant:				
Land and improvements	$ 79,319	$ 814	$ -	$ 80,133
Construction in progress	243,245	98,658	(81,062)	260,841
Total nondepreciable utility plant	322,564	99,472	(81,062)	340,974
Nuclear fuel*	105,507	70,411	(29,020)	146,898
Depreciable utility plant:				
Generation - Fossil	1,695,943	15,911	(2,949)	1,708,905
Generation - Nuclear	1,354,731	17,398	(2,895)	1,369,234
Transmission	1,426,109	23,634	(5,785)	1,443,958
Distribution	261,504	18,222	(12,047)	267,679
General	386,451	22,052	(23,015)	385,488
Total depreciable utility plant	5,124,738	97,217	(46,691)	5,175,264
Less reserve for depreciation	(3,034,216)	(115,315)	46,691	(3,102,840)
Depreciable utility plant, net	2,090,522	(18,098)	-	2,072,424
Utility plant activity, net	$ 2,518,593	$ 151,785	$ (110,082)	$ 2,560,296

* Nuclear fuel decreases represented amortization of $29.0 million.

5. LONG-TERM CAPACITY CONTRACTS:

Long-term capacity contracts include the District's share of the construction costs of OPPD's 664 MW 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 $66.5 million and $62.1 million as of December 31, 2023 and 2022, respectively. The unamortized amount of the plant capacity contract was $111.1 million and $116.1 million as of December 31, 2023 and 2022, respectively, of which $4.4 million was included in Prepayments and other current assets as of December 31, 2023 and 2022. The District's share of NC2 working capital was also included in Prepayments and other current assets and was $8.0 million and $7.4 million as of December 31, 2023 and 2022, 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 $80.5 million and $78.2 million as of December 31, 2023 and 2022, respectively. The unamortized amount of the Central capacity contract was $6.2 million and $8.5 million as of December 31, 2023 and 2022, respectively, of which $2.3 million was included in Prepayments and other current assets as of December 31, 2023 and 2022.

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 $1.7 million and $1.5 million in 2023 and 2022, respectively.

6. INVESTMENT IN THE ENERGY AUTHORITY:

The District has an investment in 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, 2023 and 2022. In addition to the District, the following utilities have interests of 17.65% each as of December 31, 2023: 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, 2023: City Utilities of Springfield, Missouri, and Gainesville Regional Utilities (Florida). The Municipal Energy Authority of Georgia terminated its interest in TEA on March 31, 2024, which increased the District's interest in TEA to 21.43% on April 1, 2024. There were no significant financial impacts to the District other than the increased ownership percentage from this change.

Such investment was $27.9 million and $26.2 million as of December 31, 2023 and 2022, 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 activities by TEA. Such guarantees have been authorized as Credit Obligations under the General Resolution on a parity with the General Revenue Bonds. 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 was $60.0 million, as of December 31, 2023, 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, 2023 and 2022.

Financial statements for TEA may be obtained at The Energy Authority, 1301 Riverplace Blvd., Suite 2700, Jacksonville, Florida, 32207.

7. DEBT:

The following table summarizes debt balances as of December 31, 2023 and 2022, and debt activity for 2023 (in 000's):

	Total Debt at December 31, 2022	Increases	Decreases	Total Debt at December 31, 2023	Long-Term Debt at December 31, 2023	Current Liabilities at December 31, 2023
Revenue bonds	$ 1,070,642	$ 161,424	$ (245,182)	$ 986,884	$ 921,774	$ 65,110
Revolving credit agreements	148,732	42,937	(43,899)	147,770	38,035	109,735
Total debt activity	$ 1,219,374	$ 204,361	$ (289,081)	$ 1,134,654	$ 959,809	$ 174,845

The following table summarizes debt balances as of December 31, 2022 and 2021, and debt activity for 2022 (in 000's):

	Total Debt at December 31, 2021	Increases	Decreases	Total Debt at December 31, 2022	Long-Term Debt at December 31, 2022	Current Liabilities at December 31, 2022
Revenue bonds	$ 1,186,876	$ -	$ (116,234)	$ 1,070,642	$ 965,517	$ 105,125
Revolving credit agreements	159,793	55,068	(66,129)	148,732	148,732	-
Total debt activity	$ 1,346,669	$ 55,068	$ (182,363)	$ 1,219,374	$ 1,114,249	$ 105,125

<u>General Revenue Bonds</u>

In June 2023, the District issued $149.6 million of General Revenue Bonds, 2023 Series A at a premium of $11.8 million for the principal purpose of refunding of the District's outstanding General Revenue Bonds, 2020 Series A, to refund a portion of the outstanding TERCA indebtedness, and to fund capitalized interest on the General Revenue Bonds, 2023 Series A. The refunding was completed with $161.4 million of the proceeds from the General Revenue Bonds, 2023 Series A and $0.4 million of other available funds. The 2020 Series A bonds were issued to fund a portion of the R-Project, a capital project for approximately 226 miles of 345 kV transmission line. Additional information on the R-Project can be found in the Notes to Financial Statements, specifically Note 12.D., *SPP Membership and Transmission Agreements*, and Note 12.F., *Environmental, Endangered Species Act.*

On December 29, 2022, the District legally defeased $31.6 million of General Revenue Bonds, 2012 Series B, which were redeemed on January 1, 2023.

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% for fiscal years ended September 30, 2023 and 2022, respectively.

There were outstanding principal amounts aggregating $3.4 million and $3.9 million from legal defeasances of General Revenue Bonds, 2017 Series A, as of December 31, 2023 and 2022, 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, 2023, are as follows (in 000's):

Year	Debt Service Payments	Principal Payments
2024	$ 107,771	$ 65,110
2025	117,905	78,030
2026	99,318	62,815
2027	97,067	63,295
2028	231,194	203,860
2029-2033	301,508	217,240
2034-2038	187,825	150,075
2039-2043	76,940	66,875
2044-2045	5,615	5,220
Total Payments	$ 1,225,143	$ 912,520

The fair value of outstanding General Revenue Bonds was determined using currently published rates. The fair value was estimated to be $956.9 million and $1,018.9 million as of December 31, 2023 and 2022, respectively.

Tax-Exempt Revolving Credit Agreement

The District entered into a TERCA with a commercial bank to provide for loan commitments to the District up to an aggregate amount not to exceed $150.0 million. Per TERCA, the District's loan commitment is restricted to a maximum of 25% of the Debt of the District represented by outstanding bonds issued. This restriction was not applicable in 2023 as the outstanding balance was below the maximum amount. The District had an outstanding balance under the TERCA of $38.0 million and $47.9 million as of December 31, 2023 and 2022, respectively. As such, the remaining credit available under TERCA was $112.0 million and $102.1 million as of December 31, 2023 and 2022, 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 amended and renewed on September 15, 2022, with a termination date of September 12, 2025.

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. Per TRCA, the District's loan commitment is restricted to a maximum of 25% of the Debt of the District represented by outstanding bonds issued. The District had outstanding bonds of $912.5 million and $993.8 million as of December 31, 2023 and 2022, respectively. Thus, the maximum allowed TRCA borrowings were capped at $228.1 million and $248.5 million as of December 31, 2023 and 2022, respectively. The District had outstanding balances under the TRCA of $109.7 million and $100.8 million, as of December 31, 2023 and 2022, respectively. As such, the remaining credit available under TRCA, using the allowance to increase the loan commitments to $300.0 million, because of the restriction to a maximum of 25% of outstanding bonds, was $118.4 million and $147.7 million as of December 31, 2023 and 2022, 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	2023	2022
General Revenue Bonds:			
2010 Series A Taxable Build America Bonds:			
Serial Bonds: 2023–2024	4.63% - 4.73%	$ 5,695	$ 11,225
Term Bonds: 2025–2029	5.323%	27,985	27,985
2030–2042	5.423%	54,190	54,190
2012 Series B:			
Serial Bonds: 2023–2032	2.875% - 5.00%	4,945	5,405
Term Bonds: 2033–2036	3.625%	2,320	2,320
2037–2042	3.625%	4,155	4,155
2015 Series A-1 Serial Bonds 2023–2034	3.00% - 5.00%	104,745	116,780
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 2023–2035	5.00%	41,730	46,455
2016 Series D:			
Serial Bonds: 2023–2035	3.00% - 5.00%	15,620	16,580
Term Bonds: 2036–2040	5.00%	9,505	9,505
2041–2045	5.00%	12,140	12,140
2016 Series E Taxable Serial Bonds 2023–2033	2.552% - 3.567%	47,980	52,060
2017 Series A Serial Bonds 2023–2027	3.00% - 5.00%	1,775	2,335
2017 Series B Serial Bonds 2023–2027	5.00%	23,480	28,660
2019 Series A Serial Bonds 2023–2034	5.00%	27,695	29,590
2019 Series B-1 Taxable Serial Bonds 2023–2028	2.166% - 2.593%	56,705	72,325
2019 Series B-2 Taxable Serial Bonds 2023–2028	2.166% - 2.593%	12,190	15,810
2020 Series A Serial Bonds 2024–2050	0.60%	-	125,825
2021 Series A Serial Bonds 2024–2039	5.00%	68,140	68,140
2021 Series B Serial Bonds 2028–2040	5.00%	50,580	50,580
2021 Series C Serial Bonds 2023–2031	5.00%	45,035	95,495
2021 Series D:			
Serial Bonds: 2024–2026	5.00%	2,555	2,555
Term Bonds: 2041–2043	4.00%	18,720	18,720
2023 Series A Term Bonds 2028	5.00%	149,640	-
Total par amount of General Revenue Bonds		912,520	993,830
Unamortized premium net of discount		74,364	76,812
		986,884	1,070,642
Less – current maturities of General Revenue Bonds		(65,110)	(105,125)
Long-term General Revenue Bonds		$ 921,774	$ 965,517

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 $10.2 million for December 31, 2023 and 2022, 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, were as follows (in 000's):

Description	2023	2022
Cooper Nuclear Station license termination costs	$ 816,852	$ 832,439
GGS and Sheldon ash landfills	11,469	11,011
Ainsworth Wind Energy Facility	7,616	7,369
Underground storage tanks	1,000	1,000
	$ 836,937	$ 851,819

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 asset retirement obligations for Cooper Nuclear Station license termination costs were based on external studies completed in 2023 and 2019, respectively. The 2023 study estimated costs for two scenarios: 1) immediate commencement of decommissioning after license termination in 2034; and 2) safe storage for 60 years after license termination. The 2019 study included an additional scenario for delayed decommissioning for 46 years after license termination. An expert panel, consisting of District management representatives with considerable nuclear experience, assigned probabilities to these different scenarios. Weighted probabilities were used when calculating the ARO. No consumer price adjustment was required for the 2023 obligation amount as the study was in 2023 dollars. The CPI-U of 6.45% was used to adjust the obligation in 2022 from the prior year amount. Nuclear decommissioning fund balances were $634.5 million and $602.5 million as of December 31, 2023 and 2022, 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. NDEE provided inflation factors based on the Implicit Price Deflator for the Gross Domestic Product of 3.64% and 6.98% for 2023 and 2022, respectively. The District provided guarantees and financial assurance through correspondence and supporting information to NDEE. The costs in rates plus interest for the decommissioning of the ash landfills were $0.9 million and $0.8 million for 2023 and 2022, respectively. The rate collections and interest 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. In 2023, the operational life for the Ainsworth Wind Energy Facility was extended through December 31, 2030. The 2023 and 2022 ARO was based on an external study completed in 2021 for costs using one scenario. There are no legally required funding and assurance provisions associated with this ARO. The costs included in rates plus interest for the decommissioning of the Ainsworth Wind Energy Facility were $1.5 million and $1.4 million for 2023 and 2022, respectively. The rate collections and interest reduced the related deferred outflow for the 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. There have not been any decommissioning costs for the underground storage tanks included in rates.

10. RETIREMENT PLAN:

The Nebraska Public Power District 401(k) Plan (the "Plan") was established and administered by the District to help supplement retirement income of participating regular full-time and part-time employees. There were 1,975 and 1,962 active Plan members as of December 31, 2023 and 2022, 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. The Plan permits Pre-tax and Roth Elective deferral contributions. 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 eligible earnings up to $75,000. On eligible earnings greater than $75,000, the District contributes one times the Plan member's contribution. The Participants' contributions were $19.2 million and $17.9 million for 2023 and 2022, respectively. The District's matching contributions were $17.4 million and $16.4 million for 2023 and 2022, respectively. Total contributions of $1.8 million were accrued in accounts payable and accrued liabilities for both years as of December 31, 2023 and 2022.

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. There were 811 and 771 active Plan members as of December 31, 2023 and 2022, respectively. 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 $3.0 million and $2.7 million for 2023 and 2022, 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 in disability status and their eligible 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 hospital-medical benefits based on hire date and/or the age of the employee. These benefits include a self-insured Pre-Medicare plan, fully-insured Medicare Supplement and Part D Plans, 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 for 2023 of $4,244 and $2,122 for pre-age 65 and post-age 65 retirees, respectively. The Board authorized an increase in these annual amounts to $4,456 and $2,228 for 2024. The District also provides a postemployment death benefit for $5,000 for qualifying employees.

Summary of Hospital-Medical Benefits by Hire Date

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:

	2023	2022
Active employees	1,927	1,914
Inactive employees or beneficiaries in retirement status	1,473	1,455
Inactive employees or beneficiaries in long-term disability status	41	42
Total employees covered by benefit terms	3,441	3,411

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

	2023	2022
Active employees	1,927	1,914
Inactive employees in retirement status	1,335	1,312
Inactive employees in long-term disability status	46	46
Total employees covered by benefit terms	3,308	3,272

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 $2.9 million and $6.3 million for 2023 and 2022, respectively.

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 2023 and 2022. 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, 2023, and January 1, 2022. 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, 2023 and 2022, respectively actuarial valuation were based on the results of an actuarial experience study completed during 2018. The total OPEB liability in the January 1, 2023 and 2022, 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: 6.9% initial for 2023, ultimate 4.5% Post-Medicare: 7.3% initial for 2023, ultimate 4.5% Pre-Medicare: 6.4% initial for 2022, ultimate 4.5% Post-Medicare: 6.7% initial for 2022, ultimate 4.5%
RRA increase rate	3.0%
Administrative cost trend	3.0%
Inflation	2.4% for 2023 and 2.2% for 2022
Salary increases	4.0%
Investment rate of return	6.25% for 2023 and 5.75% 2022, net of investment expense, including inflation
Discount rate	6.25% for 2023 and 5.75% 2022, 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-2021
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:

		Long-Term Expected Real Rate of Return	
Asset Class	Target Allocation	2023	2022
Equity and Real Estate	70%	7.6%	6.6%
Fixed Income	30%	4.3%	2.6%
Total	100%	6.9%	5.6%

Discount Rate

The discount rate used to measure the total OPEB liability was 6.25% and 5.75% for the actuarial valuations as of January 1, 2023 and 2022, 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.

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

The following table shows the total OPEB liability, plan fiduciary net position and net OPEB (asset)/liability as of January 1, 2023, and the changes during this period, based on the valuation measurement date of January 1, 2023 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB (Asset)/Liability (a-b)
Balances at January 1, 2022	$ 319,778	$ 402,342	$ (82,564)
Changes for the year:			
Service cost	2,693	-	2,693
Interest	18,064	-	18,064
Differences between expected and actual experience	(7,325)	-	(7,325)
Changes of assumptions	(8,939)	-	(8,939)
Contributions - employer	-	6,294	(6,294)
Net investment income	-	(65,647)	65,647
Benefit payments	(16,867)	(16,867)	-
Administrative expense	-	(212)	212
Net changes	(12,374)	(76,432)	64,058
Balances at January 1, 2023	$ 307,404	$ 325,910	$ (18,506)

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

The following table shows the net OPEB (asset)/liability of the District, as well as what the net OPEB (asset)/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, 2023 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB (Asset)/Liability	$ 17,931	$ (18,506)	$ (49,159)

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

The following table shows the net OPEB (asset)/liability of the District, as well as what the net OPEB (asset)/liability would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 5.9% initial to 3.5% ultimate, Post-Medicare ranging from 6.3% initial to 3.5% ultimate) or 1-percentage-point higher (Pre-Medicare ranging from 7.9% initial to 5.5% ultimate, Post-Medicare ranging from 8.3% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 6.9% initial to 4.5% ultimate, Post-Medicare ranging from 7.3% initial to 4.5% ultimate) at the measurement date of January 1, 2023 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB (Asset)/Liability	$ (47,633)	$ (18,506)	$ 15,967

The following table shows the total OPEB liability, plan fiduciary net position and net OPEB (asset)/liability as of January 1, 2022, and the changes during this period, based on the valuation measurement date of January 1, 2022 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB (Asset)/Liability (a-b)
Balances at January 1, 2021	$ 309,022	$ 343,549	$ (34,527)
Changes for the year:			
Service cost	2,663	-	2,663
Interest	18,237	-	18,237
Differences between expected and actual experience	(7,054)	-	(7,054)
Changes of assumptions	12,620	-	12,620
Contributions - employer	-	28,283	(28,283)
Net investment income	-	46,479	(46,479)
Benefit payments	(15,710)	(15,710)	-
Administrative expense	-	(259)	259
Net changes	10,756	58,793	(48,037)
Balances at January 1, 2022	$ 319,778	$ 402,342	$ (82,564)

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

The following table shows the net OPEB (asset)/liability of the District, as well as what the net OPEB (asset)/liability would be if it were calculated using a discount rate that is 1-percentage-point lower (4.75%) or 1-percentage-point higher (6.75%) than the discount rate (5.75%) at the measurement date of January 1, 2022 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB (Asset)/Liability	$ (43,053)	$ (82,564)	$ (115,637)

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

The following table shows the net OPEB (asset)/liability of the District, as well as what the net OPEB (asset)/liability would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 5.4% initial to 3.5% ultimate, Post-Medicare ranging from 5.7% initial to 3.5% ultimate) or 1-percentage-point higher (Pre-Medicare ranging from 7.4% initial to 5.5% ultimate, Post-Medicare ranging from 7.7% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 6.4% initial to 4.5% ultimate, Post-Medicare ranging from 6.7% 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	$ (114,260)	$ (82,564)	$ (44,815)

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 a negative $9.1 million for 2023, 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 $2.9 million for 2023.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2023 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ -	$ 37,280
Changes in assumptions	14,144	8,534
Difference between actual and expected earnings	70,782	32,470
Contributions made during the year ended December 31, 2023	2,850	-
	$ 87,776	$ 78,284

The deferred outflows of resources related to the contributions made during the year ended December 31, 2023 will be recognized in the actuarial valuation with a measurement date of January 1, 2024. 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
2024	$ (9,747)
2025	(1,126)
2026	6,549
2027	14,789
2028	(1,702)
2029	(2,121)
Total	$ 6,642

OPEB expense was negative $24.8 million for 2022, as calculated under the GASB guidance, 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 $6.3 million for 2022.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2022 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ -	$ 43,780
Changes in assumptions	17,377	1,230
Difference between actual and expected earnings	3,744	48,954
Contributions made during the year ended December 31, 2022	6,294	-
	$ 27,415	$ 93,964

The deferred outflows of resources related to the contributions made during the year ended December 31, 2022 were recognized in the actuarial valuation with a measurement date of January 1, 2023. 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
2023	$ (22,609)
2024	(25,086)
2025	(16,464)
2026	(8,790)
2027	(549)
2028	655
Total	$ (72,843)

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 $115.0 million at December 31, 2023. 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.

The District has contracts for uranium to uranium-hexafluoride conversion services through 2026. Contracts are also in place for all requirements of enrichment and fuel fabrication services through the final reload before the end of the current operating license of Cooper Nuclear Station which is January 18, 2034. The District currently has no purchase contracts in place for procuring uranium. The District has adequate uranium supplies in inventory that are expected to be needed up through the 2026 core reload. These commitments for nuclear fuel material and services including fabrication have combined estimated future payments of $213.4 million.

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 (23.7%). No such default has occurred to date.

The District had a participation power sales agreement with MEAN for the sale to MEAN of the capacity and energy from Gerald Gentleman Station and Cooper Nuclear Station of 50 MW which began January 1, 2011 and continued 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 capacity 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. The cost of fuel is based on the amount of energy scheduled by Lincoln. In addition, the District is required to provide substitute energy to Lincoln under certain circumstances. 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 payments of these wholesale purchase commitments were $31.8 million for 2023. The annual minimum future payments 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 nominally-rated 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 capacity 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 2023 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. The District is required to pay all costs of Central attributable to the maintenance and operation of the Kingsley Project including reserves.

C. *Retail Agreements and Wholesale Power Contracts –*

<u>Retail Agreements</u>

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 2047. These 77 retail PRO Agreement customers represented 76.3% of retail revenues for 2023. 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.

<u>Wholesale Power Contracts</u>

The District serves its wholesale customers under total requirements contracts that require them to purchase total power and energy requirements from the District, subject to certain exceptions. The District has Wholesale Power Contracts ("2016 Contracts") with 22 public power districts, one cooperative, and 37 municipalities, through 2035.

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 45^{th} 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 do 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 2018 to 2022 set forth in the CFC Data:

CFC Data	
Year	Percentile
2018	26.9%
2019	29.5%
2020	23.2%
2021	12.4%
2022	11.7%

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 NTC 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 226 miles of 345 kV transmission line from Gerald Gentleman Station, north to a substation east of Thedford, then eastward to an existing 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 the outcome of litigation, which is discussed further in this Note in section 12.F., *Environmental, Endangered Species Act*.

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 NTC 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 estimated cost approved by SPP for the R-Project is $486.1 million. If the updated District cost estimate exceeds the SPP escalated baseline by more than 20.0%, the District would need to seek approval from SPP. The District awarded a contract for the construction of the R-Project in January 2019. The District has spent approximately $156.4 million through December 31, 2023, 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 required 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 for 2021. On July 31, 2022 the District and Entergy mutually agreed to terminate the Entergy agreement without cause resulting in no termination fees.

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 2042 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 claims through 2013. The District and the DOE have executed several extensions of this agreement through 2022. Settlements from the DOE for damages totaled $139.9 million for the years 2009 through 2023. The District and the DOE are currently negotiating a three-year extension. 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, 2023 and 2022.

Under the terms of the DOE contracts, the District was also subject to a one mill per 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 ROP monitors licensee performance in three broad strategic performance areas: reactor safety, radiation safety and safeguards. The process focuses on licensee performance within each of the seven cornerstones of safety included in the three strategic areas. Results from the monitor cornerstones are compiled and published in the NRC’s ROP Action Matrix Summary. Best performing plants are included in the Licensee Response Column where routine inspector and staff interaction is the norm. As of December 31, 2023, 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 28, 2022 and was completed on November 12, 2022. During this outage, in addition to replacing 188 fuel assemblies and conducting routine maintenance and inspections, the emergency station startup transformer, main generator exciter and a reactor feed pump turbine were replaced. The next refueling and maintenance outage is currently planned for the fall of 2024.

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 $25.6 million as of December 31, 2023, and will be eliminated through revenue recognition during the 2024 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. The NDEE issued the District six NPDES permits for the following facilities: Gerald Gentleman Station, Sheldon Station, Cooper Nuclear Station, Beatrice Power Station, Canaday Station and the North Platte Office Building. Four of these facilities have storm water management plans. Cooper Nuclear Station and Gerald Gentleman Station have received Section 316(a) waivers.

Section 316(b) of the Clean Water Act requires that NPDES permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures reflect the Best Technology Available (“BTA”) to minimize harmful impacts on fish and other aquatic life as the result of impingement or entrainment. The EPA issued the final rule under Section 316(b) on August 15, 2014. Under the final rule Cooper Nuclear Station, Gerald Gentleman Station, and Canaday Station had to identify the chosen compliance method for each facility.

The NDEE determined that the current entrainment technology was the BTA as Cooper Nuclear Station and Gerald Gentlemen Station. The District subsequently selected and recommended screen modification to the NDEE that were approved by the NDEE and incorporated into the respective NPDES permits. The initial designs and engineering plans for the modified traveling screens were approved by the NDEE. The installation of the modifications for Cooper Nuclear Station must begin by October 1, 2024, and must be installed by July 1, 2025, and modifications for Gerald Gentlemen Station must begin by July 1, 2024, and must be installed by September 1, 2026. 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 ELG 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 has no impact on Cooper Nuclear Station, Gerald Gentleman Station, or Canady Station. Sheldon Station will be required to comply with the Effluent Rule for its bottom ash transport water. On August 31, 2020, the EPA Administrator signed the Steam Electric Reconsideration Rule, which modified the existing Effluent Rule. The Reconsideration Rule allowed for three compliance options for bottom ash transport water: 1) modify the bottom ash transport system to operate as a zero-discharge system, or; 2) modify the bottom ash transport system to operate as high recycle system and discharge up to ten percent of the bottom ash transport water, or; 3) commit to no longer burning coal by December 31, 2028. The District selected to install a high recycle system and submitted an initial certification statement on April 15, 2022. The deadline for completion of any construction upgrades to comply with the Effluent Rule is December 31, 2025.

On March 29, 2023, the EPA released the proposed "Supplemental Effluent Limitations Guidelines and standards for the Steam Electric Power Generating Point Source Category." The proposed rule would require a zero-discharge system by December 31, 2029, at Sheldon Station, which the District plans to install to comply with the expected requirements of the final rule. The final rule is expected to be released in May 2024. The cost to install the zero-discharge system is approximately $4.9 million.

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 2030, the District expects to have sufficient Acid Rain allowances to cover affected facilities through 2030 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. The Mercury and Air Toxics Standards ("MATS") Rule will reduce emissions from new and existing coal and oil-fired steam utility electric generating units of heavy metals, including mercury, arsenic, chromium, nickel, dioxins, furans, and acid gases, including hydrogen chloride and hydrogen fluoride. These toxic air pollutants are also known as hazardous air pollutants. The affected District facilities, which are Gerald Gentleman Station and Sheldon Station, are in compliance with the MATS Rule.

On April 24, 2023, the EPA issued the proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review rule that would reduce the filterable PM emission limit for coal-fired facilities and require the facilities to install continuous PM monitors. The final rule is expected to be issued in May 2024. Stack testing, which is not continuous monitoring, at Gerald Gentleman Station and Sheldon Station have indicated that the District should be able to comply with the proposed lower PM emission limits.

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 2030, the District expects to have sufficient CSAPR allowances to cover affected facilities emission requirements through 2030 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 and updated those regulations in 2017. 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. The program is being implemented over 60 years in 10-year planning phases, with the goal of reaching "natural conditions" for visibility in all Class I areas by 2064. The District's Sheldon Station Unit No. 1 and Gerald Gentleman Station Units No. 1 and No. 2 were subject to the first phase of Regional Haze evaluation. Sheldon Station Unit No. 2 was not subject to the first phase evaluation due to its initial start-up date. Canaday Station and Beatrice Power Station will also not be affected in the first phase of the Regional Haze Program.

On June 5, 2020, the District received an Information Collection Request ("ICR") from the NDEE for information pertaining to the second planning phase (2018-2028). Based on screening performed by Central States Air Resources Agencies, the NDEE determined that Gerald Gentleman Station may contribute to the visibility impairment at multiple Class I areas. The NDEE ICR requested information regarding the cost to install and operate four SO_2 control 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 response on December 30, 2020. Comprehensive air quality visibility modeling submitted by the District to NDEE demonstrates that all relevant Class I areas are making reasonable progress on visibility improvement, that Gerald Gentleman Station does not contribute significant visibility impairment to any Class I area, and that adding additional controls or emission limitation to Gerald Gentleman Station and other coal-fired units in Nebraska would not produce a significant change in visibility in any Class I area.

In late 2022, the NDEE shared a draft State Implementation Plan ("SIP") with the federal land managers, who provided comments in January 2023. On September 6, 2023, the NDEE public noticed the draft SIP and held a public hearing on November 9, 2023. NDEE is preparing a response to the comments received during the public notice and hearing and is expected to submit the final SIP to the EPA by the end of 2024.

The current draft of the SIP does not recommend any additional controls for the second implementation period (ending in 2028). The District does not know if it will be required to install and operate any of the SO_2 control options referred to above in the future. 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 Gerald Gentleman Station.

<u>Clean Power Plan</u>
On October 23, 2015, the EPA published the final Clean Power Plan ("CPP") rule addressing carbon dioxide reductions from existing fossil-fueled power plants in the Federal Register. On June 19, 2019, the EPA issued the Affordable Clean Energy ("ACE") rule that replaced the CPP rule. Both the CCP and ACE rules were issued by the EPA under Section 111(d) of the Clean Air Act. The ACE rule and the replacement of the CPP rule were appealed to the D.C. District Court. On January 19, 2021, the D.C. Circuit Court vacated the ACE rule and reinstated the CPP rule, which decision was appealed to the United States Supreme Court. On June 30, 2022, the United States Supreme Court in West Virginia v. EPA held the CPP rule exceeded the authority of EPA under section 111(d).

On May 11, 2023, the EPA proposed new CO_2 regulations for electric generation facilities which utilize natural gas, coal, or oil. The proposed regulations would require varying compliance obligations depending on fuel type, capacity factor, and remaining life of the specific generating unit. Coal plants scheduled to operate beyond 2040 would require 90% carbon capture and sequestration by 2030. Carbon sequestration is also required for certain large, baseload natural gas plants. Co-firing with natural gas is an option for certain coal plants and co-firing with green hydrogen would be an option for certain natural gas plants. The proposed regulations received extensive comments. The EPA has indicated that regulation of existing natural gas fired CTs will be removed from the final rule and addressed in a separate rule making. At this time, the District cannot predict the final form of the proposed regulations, but the cost of compliance could be substantial and could impact the economic viability of certain units, even assuming the compliance options are commercially available. The proposed rule is expected to become final by June 2024 and is also expected to be challenged in the courts.

<u>Endangered Species Act</u>
The District applied to the U.S. Fish and Wildlife Service ("USFWS") under Section 10 of the Endangered Species Act ("ESA") for an Incidental Take Permit ("ITP") for the American burying beetle ("Beetle"), which is a threatened 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") under the National Environmental Policy Act ("NEPA") regarding the R-Project proposed ITP to assess impacts on the environment. The FEIS describes the R-Project, certain alternatives, environmental impacts of the R-Project and certain alternatives thereto, 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.

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, NEPA, 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. 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 and USFWS both decided not to appeal the district court's decision. The USFWS has commenced the process of addressing the court's decision on remand, which involves, among other things, initiating the NEPA process for a supplement to the FEIS. On November 18, 2022, the USFWS issued a Notice of Intent to prepare a supplemental environmental impact statement for the R-Project and announced a 30-day public scoping period that ended on December 19, 2022. On February 9, 2024, the USFWS issued a Draft Supplemental Environmental Impact Statement for public comment. The District anticipates recommencing construction activities for the R-Project once the USFWS completes the remand process and issues a new ITP and the District has obtained any other permit or agency authorization required for the project.

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 or transmission facilities 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 severely damaged due to an inflow of ice and water.

Decommissioning the Spencer Hydro Facility will require approval from the Nebraska Department of Natural Resources (the "NDNR"), which regulates the Spencer Hydro Facility, with input from other state and federal agencies. The estimated cost to decommission the Spencer Hydro Facility is approximately $9.0 million. Decommissioning work is expected to begin in November 2024.

The District was 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 lawsuit has been settled and dismissed. 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 discovery. At this time, it is not possible to predict the outcome of the said lawsuit or any other claims that may arise.

The District maintains property and liability insurance and has notified its carriers of the events at the Spencer Hydro Facility and received a $5.0 million settlement payment for the property damage to said facility. The District also expects to receive compensation from the Federal Emergency Management Agency to assist with the cost of decommissioning.

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.*

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.

REQUIRED SUPPLEMENTARY INFORMATION (UNAUDITED)

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

Total OPEB Liability	2023	2022	2021	2020	2019	2018	2017	2016
Service Cost	$ 2,693	$ 2,663	$ 2,103	$ 2,299	$ 2,771	$ 2,760	$ 3,322	$ 3,229
Interest	18,064	18,237	18,775	19,604	19,661	20,032	20,658	19,876
Changes of Benefit Terms	-	-	8,598	-	-	-	-	-
Differences between Expected and Actual Experiences	(7,325)	(7,054)	(20,995)	(19,961)	(8,686)	(19,570)	(203)	13,657
Changes of Assumptions	(8,939)	12,621	9,367	(1,608)	(751)	5,585	(18,807)	(9,149)
Benefit Payments, net of employee contributions	(16,867)	(15,710)	(14,026)	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Net Change in Total OPEB Liability	(12,374)	10,757	3,822	(12,473)	(1,065)	(6,607)	(8,489)	10,711
Total OPEB Liability (Beginning)	319,778	309,021	305,199	317,672	318,737	325,344	333,833	323,122
Total OPEB Liability (Ending) (a)	$ 307,404	$ 319,778	$ 309,021	$ 305,199	$ 317,672	$ 318,737	$ 325,344	$ 333,833
Plan Fiduciary Net Position								
Contributions	$ 6,294	$ 28,283	$ 28,283	$ 41,084	$ 56,706	$ 28,439	$ 74,711	$ 28,242
Net Investment Income (Loss)	(65,647)	46,479	47,237	41,733	(6,892)	21,350	6,102	(453)
Benefit Payments, net of employee contributions	(16,867)	(15,710)	(14,026)	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Administrative Expense	(212)	(259)	(205)	(188)	(130)	(70)	(69)	(150)
Net Change in Plan Fiduciary Net Position	(76,432)	58,793	61,289	69,822	35,624	34,305	67,285	10,737
Plan Fiduciary Net Position (Beginning)	402,342	343,549	282,260	212,438	176,814	142,509	75,224	64,487
Plan Fiduciary Net Position (Ending) (b)	$ 325,910	$ 402,342	$ 343,549	$ 282,260	$ 212,438	$ 176,814	$ 142,509	$ 75,224
Net OPEB (Asset)/Liability (Ending) (a) - (b)	$ (18,506)	$ (82,564)	$ (34,528)	$ 22,939	$ 105,234	$ 141,923	$ 182,835	$ 258,609
Net Position as a % of Total OPEB (Asset)/Liability	106.0%	125.8%	111.2%	92.5%	66.9%	55.5%	43.8%	22.5%

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

	2023	2022	2021	2020	2019	2018	2017	2016
Actuarially Determined Contribution	$ 2,404	$ 2,847	$ 2,871	$ 6,676	$ 12,967	$ 18,572	$ 21,006	$ 28,283
Contributions Made in Relation to the Actuarially Determined Contribution	2,850	6,294	28,283	28,283	41,084	56,706	28,439	74,712
Contribution Deficiency (Excess)	$ (446)	$ (3,447)	$ (25,412)	$ (21,607)	$ (28,117)	$ (38,134)	$ (7,433)	$ (46,429)

Schedules of Investment Returns for Years Ended December 31,

	2023	2022	2021	2020	2019	2018	2017	2016
Annual Money-Weighted Rate of Return, Net of Investment Expense	14.9%	(16.6%)	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 –

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	10-year closed period for 2023, 11-year closed period for 2022, 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: 6.9% initial, ultimate 4.5% for 2023 Post-Medicare: 7.3% initial, ultimate 4.5% for 2023 Pre-Medicare: 6.4% initial, ultimate 4.5% for 2022 Post-Medicare: 6.7% initial, ultimate 4.5% for 2022 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
RRA increase rate	3.0%
Administrative cost trend	3.0%
Inflation	2.4% for 2023, 2.2% for 2022, 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	6.25%, net of investment expense, including inflation for 2023 and 2020 through 2016 6.0%, net of investment expense, including inflation for 2021 5.75%, net of investment expense, including inflation for 2022
Discount rate	6.25% for 2023, 5.75% for 2022, 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-2021 for 2023 and 2022 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	For 2023 through 2019, 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 2018 through 2016, 80% of males and 30% of females are assumed to have spouses who will elect coverage. Males are assumed to be three years older than their spouses. Females are assumed to be three years younger.
Participation rate	95% for 2022 through 2019, 100% for 2018 through 2016

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)	2023	2022
Operating revenues	$ 1,071,924	$ 1,196,972
Operating expenses	(1,034,664)	(1,079,904)
Operating income	37,260	117,068
Investment and other income (loss)	45,657	(10,194)
Debt and related expenses	(30,792)	(25,913)
Increase in net position	52,125	80,961
Add:		
Debt and related expenses(1)	30,792	25,913
Depreciation and amortization(2)	128,373	128,803
Payments to retail communities(3)	32,407	32,594
Amortization of current portion of financed nuclear fuel(4)	3,543	20,097
	195,115	207,407
Deduct:		
Investment income retained in construction funds(5)	751	180
Unrealized gain (loss) on investment securities	11,416	(8,396)
	12,167	(8,216)
Net revenues available for debt service under the General System Bond Resolution	$ 235,073	$ 296,584
General system bonded debt service(6)	145,163	128,222
Ratio of net revenues available for debt service(6)	1.62	2.31

(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 TRCA is excluded from the debt service calculation as the District's obligation to make payments under the TRCA is subordinate to the District's obligation to pay debt service on General Revenue Bonds.
(5) Interest income on investments held in construction funds is not Revenue as defined in the General Resolution.
(6) 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 decrease in the 2023 ratio of net revenues available for debt service (also referred to as debt service coverage) from 2022 was due primarily to a decrease in net revenues for the recognition of a $69.3 million regulatory liability for costs for the Cooper Nuclear Station and a larger amount paid for debt service in 2023. The debt service coverage for 2022 included debt service on the General Revenue Bonds, 2012 Series B, redeemed in December 2022. If the debt service on the said General Revenue Bonds so redeemed were excluded for 2022, the debt service coverage for 2022 was 2.76 times.

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