Financial Report 2024

Nebraska Public Power District
Always there when you need us

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OUR Vision

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

OUR 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 2,809 miles of distribution lines.

Revenues are primarily derived from wholesale power supply agreements with 36 municipalities and 23 public power districts and/or cooperatives. NPPD also serves an average of more than 94,000 residential, commercial and industrial customers in 81 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

2,809 MILES
DISTRIBUTION LINES

3,441.0 MW
DIVERSE GENERATION

2,000+
TEAMMATES WORKING FOR YOU

$1.2 Billion
OPERATING REVENUE

530,000
NEBRASKANS SERVED IN PARTNERSHIP WITH OTHER UTILITIES

94,000+
RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS

36
MUNICIPALITIES SERVED AT WHOLESALE

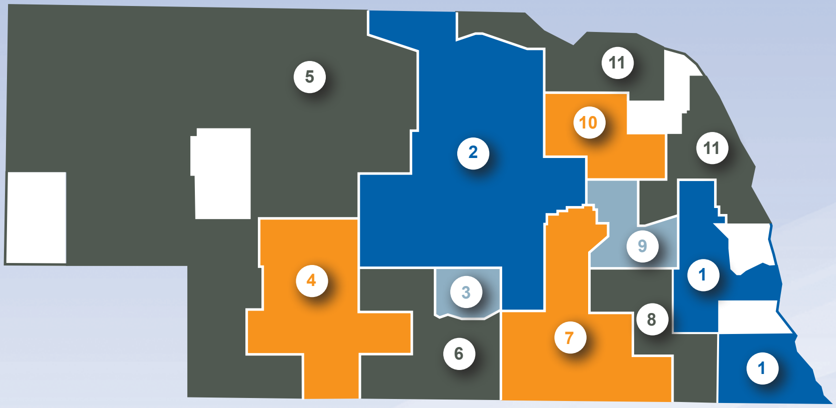
81
COMMUNITIES SERVED BY RETAIL

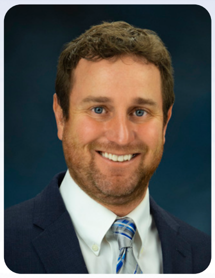
23
PUBLIC POWER DISTRICTS SERVED AT WHOLESALE

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

Kirk Olson (1)
North Platte
Subdivision 4

Rusty M. Kemp
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
Schuyler
Subdivision 11

David D. Gale (1)
North Platte
Subdivision 4

Rob Hinrichs
Axtell
2025 Board Member
(Elected in November 2024)
Subdivision 6

(1) Mr. Olson was Governor-appointed effective Aug. 22, 2024 following the resignation of Mr. Gale.

SENIOR MANAGEMENT TEAM

Thomas J. Kent
President & Chief Executive Officer

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
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

A Message

FROM OUR 2024 BOARD CHAIR and CHIEF EXECUTIVE OFFICER

The value of public power in Nebraska has always been based on its longstanding commitment to put customers first, including the need for affordable and reliable electricity. The rapidly changing dynamics of our industry have opened the door to do so in increasingly meaningful ways using technology and by leveraging our partnerships with our customers. Coupled with the changing requirements and growing energy needs from our customers, this has presented NPPD with an opportunity to take our organization and generation resources to the next level.

One of the biggest announcements was NPPD's plans to pursue new generation resources to complement our already diverse portfolio. The approval of projects to add combustion turbines and reciprocating internal combustion engines to our generation mix will help us meet growing demand for power from our customers and increase the agility, flexibility, and responsiveness of our generation resources amid changing market conditions in the Southwest Power Pool's electricity market.

As load growth continues its unprecedented upward climb, we have regularly engaged with wholesale customers on the topic of new customer contracts. Long-term contracts are vital to our ability to plan for and invest in these upcoming generation projects, and conversations on specific details of new contracts will continue into 2025.

In related news, NPPD welcomed Paxton as our 80th retail community in March, with Lodgepole officially becoming our 81st retail community in November. We also continued progress on several key transmission projects, all which seek to relieve congestion and improve reliability and resiliency in our service territory.

But these weren't the only projects we explored last year. In August, NPPD and the Nebraska Department of Economic Development announced 16 sites to explore as potential future locations for next generation nuclear in the form of Small Modular Reactors. The number will then be reduced for detailed site characterization.

Even as NPPD intently pursues ongoing continuous improvements and innovations, our retail and wholesale rates remained competitive nationally, as evidenced by national benchmarking from the Energy Information Administration and the Cooperative Finance Corporation. 2024 saw no increase in base electric rates for wholesale customers for the seventh year in a row, and for retail customers for the 11th consecutive year due to teammates' prioritization of cost management and due to the safe, responsible, and reliable operation of our power plants. These rates will continue to be affordable and competitive in 2025, although retail rates were increased for the first time in more than a decade by 2%.

It was a big year for Cooper Nuclear Station, which in July celebrated its 50th anniversary for commercial operation, and then in late September, underwent its 33rd refueling outage safely, error-free and with zero consequential events. Early in the year, the board also approved NPPD's action item to pursue relicensing of the plant until 2054. NPPD is one of only 21 utilities in the nation licensed to operate a nuclear facility. Our operation of CNS provides clean, reliable energy to our customers.

We cannot discuss operational excellence without mentioning Gerald Gentleman Station, which experienced unexpected damage to the Unit 1 generator stator from an electric arc after the unit was coming on-line from its spring outage in early May. Though a full fix of the generator will not occur until late 2025, the team's outstanding and unprecedented repair work allowed the plant to be back on-line in a month instead of 18-24 months, and this even allowed the plant to reach a new daily generation record of 32,233.1 megawatt-hours on July 24.

Speaking of excellence, safety remains a core value for NPPD, which received the American Public Power Association's (APPA) Safety Awards of Excellence. NPPD focuses on safety throughout the year, and completed several successful campaigns in its customer communities, particularly during harvest and severe weather seasons.

Notably, severe weather was the cause of our participation in several mutual aid efforts throughout the spring and summer. We provided support to Roosevelt Public Power District, Omaha Public Power District on multiple occasions, and even utilities out-of-state in Georgia and Florida. Near the year's end, NPPD received a national commendation from the APPA for these efforts.

Public power advocates for its customers, and NPPD is committed to strengthening ties with the communities we serve through regularly scheduled events and engagement opportunities throughout the year.

For example, we launched a month-long, one-of-a-kind Heroes of the Grid campaign, highlighting the wholehearted dedication of our public power workforce. A special shout-out is needed for our Customer Care Call Center, which took its five millionth call in early November.

Finally, we welcomed two new members to the NPPD board – Mr. Kirk Olson in August who serves Subdivision 4 and Mr. Rob Hinrichs in January 2025, who serves Subdivision 6. Both are welcome additions whose deep agricultural experience will help provide valuable insights on our board. Hinrichs replaces Ed Schrock, who served 18 years on the board and received recognition for his outstanding service and contributions at the year's end.

2024 was a year devoted to elevating our performance and offerings to better serve customers as we pursue our strategic goals. There has never been a more exciting time to work within our industry. All of these accomplishments and the ongoing forward momentum reflect the hard work, dedication, and teamwork of our employees, customers and communities.

Looking ahead, we remain focused on providing reliable, affordable and sustainable energy while actively engaging in initiatives that ensure public power maintains its legacy and vitality bringing the best of public power to our fellow Nebraskans for years to come.

Thomas J. Kent
President & CEO

Jerry L. Chlopek
2024 Board Chair

2024
FINANCIAL REPORT
NEBRASKA PUBLIC POWER DISTRICT

YEAR AT A GLANCE

KILOWATT - HOUR SALES		17.8	BILLION
OPERATING REVENUES	$	1,163.6	MILLION
COST OF POWER PURCHASED AND GENERATED	$	685.5	MILLION
OTHER OPERATING EXPENSES	$	469.9	MILLION
INVESTMENT AND OTHER INCOME	$	62.2	MILLION
DEBT AND RELATED EXPENSES	$	33.6	MILLION
INCREASE IN NET POSITION	$	36.8	MILLION
DEBT SERVICE COVERAGE		2.28	TIMES

2024 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	10.61 ¢	12.68 ¢	74,694	844,554	4.8	$ 107,077	9.2
Commercial	8.34 ¢	9.82 ¢	19,906	1,101,922	6.2	108,254	9.3
Industrial	4.52 ¢	4.97 ¢	62	1,906,518	10.7	94,793	8.1
Total Retail Sales	6.95 ¢	8.05 ¢	94,662	3,852,994	21.7	310,124	26.6
Wholesale:							
Municipalities[2]		5.84 ¢	36	1,310,184	7.4	76,569	6.6
Public Power Districts and Cooperatives[2]		5.32 ¢	23	8,499,522	47.9	452,465	38.9
Total Firm Wholesale Sales		5.39 ¢	59	9,809,706	55.3	529,034	45.5
Total Firm Retail and Wholesale Sales		6.14 ¢	94,721	13,662,700	77.0	839,158	72.1
Participation and Capacity Sales		5.18 ¢	5	1,041,221	5.9	53,914	4.6
Other Sales[3]		4.84 ¢	1	3,047,621	17.1	147,365	12.7
Total Electric Energy Sales		5.86 ¢	94,727	17,751,542	100.0	1,040,437	89.4
Other Operating Revenues[4]						63,688	5.5
Unearned Revenues[5]						59,512	5.1
Total Operating Revenues						$ 1,163,637	100.0

COST OF POWER PURCHASED AND GENERATED	MWh Amount	MWh %	Costs (in 000's) Amount	Costs (in 000's) %
Production[6]	13,946,357	75.1	$ 495,699	72.3
Power Purchased	4,635,025	24.9	189,834	27.7
Total Production and Power Purchased	18,581,382	100.0	$ 685,533	100.0

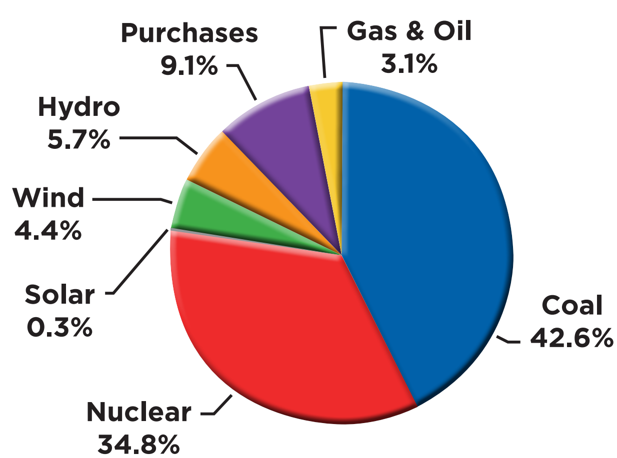
CONTRACTUAL AND TAX PAYMENTS (in 000's) [1]	Amount
Payments to Retail Communities	$ 32,164
Payments in Lieu of Taxes	10,409
Total Contractual and Tax Payments	$ 42,573

OTHER	Amount
Miles of Transmission and Subtransmission Lines in Service	5,377
Number of Full-Time Employees	2,005

(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, 2024 and 2023. The Statements of Revenues, Expenses, and Changes in Net Position present the operating results for the years 2024 and 2023. The Statements of Cash Flows present the sources and uses of cash and cash equivalents for the years 2024 and 2023. The Statements of Fiduciary Net Position present the financial resources available for other postemployment benefits ("OPEB") as of December 31, 2024 and 2023. The Statements of Changes in Fiduciary Net Position present the additions, deductions and changes in net position restricted for OPEB as of December 31, 2024 and 2023. 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, 2024 and 2023, and the results of operations for the years 2024 and 2023. 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 customers and retail customers of 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 2,005 full-time employees as of December 31, 2024. 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. In total, the District was a net seller into the SPP Integrated Market in 2024.

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 from 12.0% in 2023 to 15.0% in 2024 due to rising demand and a shift to more variable renewables. The District's highest summer peak load of 3,087.8 MW was established in August 2023 and its highest winter peak load of 2,317.5 MW was established in December 2022 for firm requirements customers.

For 2024, the District had available 3,745.2 MW of capacity resources that included 3,033.0 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. During the period of June 1, 2024, through September 30, 2024, the District also had 106 MW of capacity and an associated energy call-option with Associated Electric Cooperative, Inc. ("AECI"). Of the total capacity resources, 304.2 MW are being sold via participation sales or other capacity sales agreements, leaving 3,441.0 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 2024 accredited capacity.

	CAPACITY RESOURCES		
Type	Number of Plants(1)	Summer 2024 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	112.7	3.7
Diesel	9	68.8	2.3
Combustion Turbine(4)	3	125.9	4.2
Combined Cycle	1	219.5	7.2
Wind(5)	8	57.3	1.9
	30	3,033.0	100.0

(1) Includes three hydro plants and nine diesel plants under contract to the District.
(2) Accreditation by SPP for the summer season 2024, 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, combustion turbines ("CTs"), and reciprocating internal combustion engines ("RICE") are being pursued to meet these capacity needs. In accordance with the 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. In November 2024, the Board authorized management to execute a capacity purchase agreement with a counterparty for 300 MW of generating capacity that is deliverable to SPP from 2029 to 2035. 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 2020 through 2024.

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

Year	Coal(1)	Nuclear	Hydro(2)	Wind(3)	Gas and Oil	Purchases(4)	Solar(5)
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
2024	42.6	34.8	5.7	4.4	3.1	9.1	0.3

(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. 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 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 2024 accredited capacity and in-service dates.

DISTRICT-OWNED GENERATION FACILITIES

Facility	Fuel Type	Summer 2024 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	4.1	2005
		2,822.3	

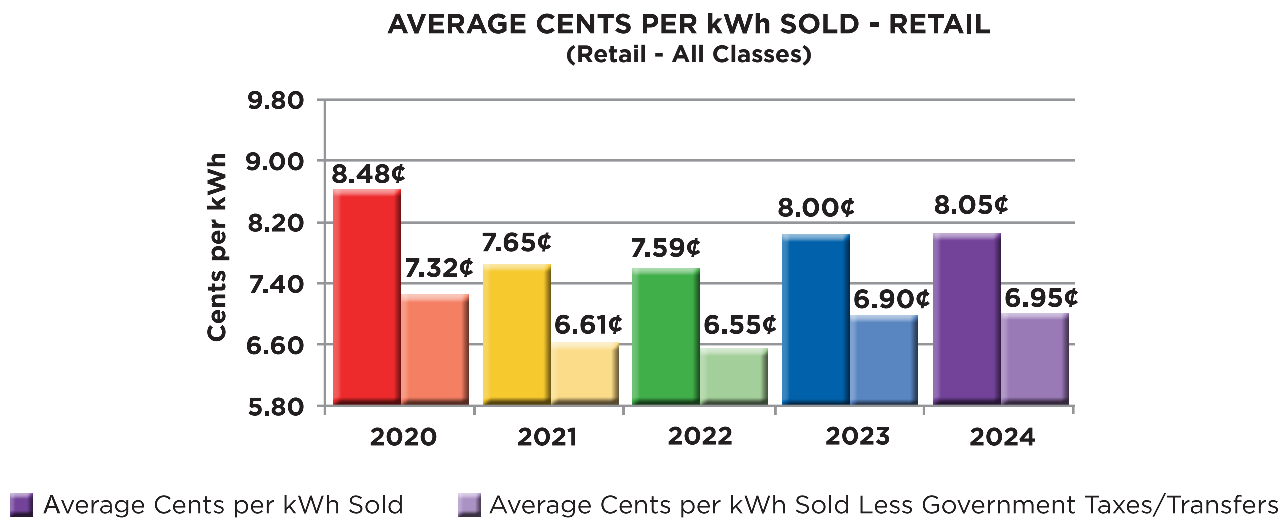
(1) 2024 summer accredited net capacity based on SPP criteria.
(2) Nominally rated at 60 MW.

THE CUSTOMERS

Retail and Wholesale Customers

In 2024, the District served an average of 94,662 retail customers. The District's retail service territory includes 79 municipal-owned distribution systems within the state of Nebraska and two tribal entities in South Dakota. Pursuant to a Professional Retail Operations Agreement ("PRO Agreement") the District operates these municipal and tribal-owned systems. The Village of Paxton, Nebraska entered into a PRO Agreement effective March 1, 2024. The Village of Lodgepole, Nebraska transitioned from a wholesale municipal customer and entered into a PRO Agreement effective November 1, 2024, which brings the number of PRO Agreements to 81. 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.

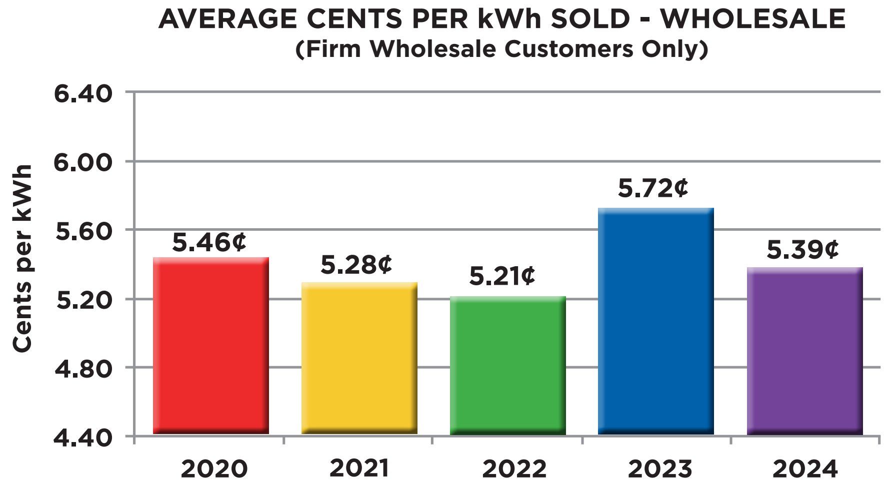
The following chart shows the District's average retail cents per kilowatt-hour ("kWh") for the years ended December 31, 2020, through 2024. The chart also shows average cents per kWh sold less customer collections for taxes and transfers to other governments, which are not included in the base rates for retail customers. The increase in the average cents per kWh sold in 2024 over 2023 was due primarily to the phase-out of the Production Cost Adjustment ("PCA") refund rate for most retail customers. The increase in the average cents per kWh sold in 2023 over 2022 was due primarily to a lower 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.



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 36 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 District's Board-approved strategic directive, 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 cost percentiles were 16.7% and 11.7% for 2023 and 2022, respectively. The CFC Data for 2024 will not be published until approximately the third quarter of 2025. 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, 2020, through 2024. The decrease in the average cents per kWh sold in 2024 from 2023 was due primarily to a $20.7 million increase in the actual PCA refunds. 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.



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 ended on December 31, 2023. The participation sales agreements with MEAN, OPPD, and Grand Island Utilities for Ainsworth Wind Energy Facility will end on September 30, 2025.

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, 2022 through 2024.

			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
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
2024	94,662	65	13,662,700	3.4	17,751,542	(8.1)	3,006.5

(1) For 2024, 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 2024 from 2023 and in 2023 from 2022 was due to a wholesale municipality customer becoming a retail customer of the District in each of those years.

(2) Native load sales include retail and wholesale sales to total firm requirements customers and the responsibility of replacement power being procured by the District if the District's generating assets are not operating. Predominantly, native load customers are served under long-term total requirements contracts. The increase in native load sales in 2024 over 2023 was due primarily to a 4.5% increase in wholesale energy sales. The decrease in native load sales in 2023 from 2022 was due primarily to weather and lower industrial 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 decrease in percentage growth for total sales in 2024 from 2023 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. The increase in percentage growth for total sales in 2023 over 2022 was due primarily to an increase in nonfirm energy sales from the Cooper Nuclear Station as it was a non-outage year.

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,	2024	2023	2022
Current Assets	$ 1,033,846	$ 1,052,977	$ 956,453
Special Purpose Funds	751,829	745,582	692,419
Utility Plant, Net	2,637,854	2,551,805	2,560,296
Other Long-Term Assets	225,079	189,999	278,312
Total Assets	4,648,608	4,540,363	4,487,480
Deferred Outflows of Resources	277,784	284,067	272,886
Total Assets and Deferred Outflows	$ 4,926,392	$ 4,824,430	$ 4,760,366
Current Liabilities	$ 505,902	$ 304,588	$ 238,192
Long-Term Debt	831,507	959,809	1,114,249
Other Long-Term Liabilities	909,968	878,951	868,019
Total Liabilities	2,247,377	2,143,348	2,220,460
Deferred Inflows of Resources:			
Unearned Revenues	224,349	258,311	267,758
Other Deferred Inflows	397,485	402,405	303,907
Net Position	2,057,181	2,020,366	1,968,241
Total Liabilities, Deferred Inflows, and Net Position	$ 4,926,392	$ 4,824,430	$ 4,760,366

Total Assets and Deferred Outflows

Total Assets as of December 31, 2024, increased $108.2 million or 2.4% over total assets as of December 31, 2023, due primarily to higher balances for special purpose funds, materials and supplies, construction work in process, nuclear fuel, net OPEB asset, and other long-term assets. Special purpose funds increased largely due to the establishment of a supplemental decommissioning fund for nuclear decommissioning costs in 2024. Materials and supplies inventories were higher due primarily 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. Construction work in progress was significantly higher due to increased capital expenditures to meet higher customer loads. Nuclear fuel inventories were higher due to increased costs and inventory levels due primarily to concerns about the Russia-Ukraine conflict and fuel availability. The net OPEB asset changed due to the increased amount the fiduciary net position exceeded the OPEB liability because of favorable market conditions. Other long-term assets increased primarily due to a newly established regulatory asset for compensated absences and increased security deposits by the District with SPP for new interconnection projects. These increases in Total Assets were partially offset by a reduction in fossil fuels inventories and amortization of the regulatory asset for OPEB.

Deferred Outflows as of December 31, 2024, decreased $6.3 million or 2.2% from deferred outflows as of December 31, 2023, due primarily to the amortization of OPEB deferred outflows in 2024. The decrease in deferred outflows was partially offset by an increase in the deferred outflows for asset retirement obligations (“ARO”), due to an increase in ARO for inflation.

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 Station which reduced the asset retirement obligation and larger investment balances to fund asset retirement obligations from rate collections and favorable market conditions.

Total Liabilities, Deferred Inflows and Net Position

Total Liabilities as of December 31, 2024, increased $104.0 million or 4.9% over total liabilities as of December 31, 2023, due primarily to higher balances for revolving credit agreements, accounts payable and accrued liabilities, accrued compensated absences, asset retirement obligations, and other current liabilities. Revolving credit agreements were higher due to increased amounts outstanding for capital projects and nuclear fuel. Accounts payable and accrued liabilities were higher due primarily to larger vendor payable balances related to capital projects, station outages, and liabilities for the employee variable pay program implemented in 2024. Accrued compensated absences were higher due to amounts owed for employee sick leave liabilities related to the implementation of new accounting guidance in 2024. Asset retirement obligations were higher due to adjustments to these liabilities for inflation. Other current liabilities were higher due primarily to an increase in customer deposits. The increase in total liabilities was partially offset by a decrease in outstanding debt balances for revenue bonds.

Deferred Inflows as of December 31, 2024, decreased $38.9 million or 5.9% from deferred inflows as of December 31, 2023, due primarily to a net reduction in rate stabilization fund balances or unearned revenues, and decreases in regulatory liabilities, including the use of the amounts pre-collected for the Cooper Nuclear Station outage that occurred in 2024.

Net Position as of December 31, 2024, increased $36.8 million over December 31, 2023. 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 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 an increase in the 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 increased $52.1 million over 2022. The reason for this change is 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,	2024	2023	2022
Operating Revenues	$ 1,163,637	$ 1,071,924	$ 1,196,972
Operating Expenses	(1,155,493)	(1,034,664)	(1,079,904)
Operating Income	8,144	37,260	117,068
Investment and Other Income (Loss)	62,224	45,657	(10,194)
Debt and Related Expenses	(33,553)	(30,792)	(25,913)
Change in Net Position	$ 36,815	$ 52,125	$ 80,961

SOURCES OF OPERATING REVENUES (in 000's)

For the years ended December 31,	2024	2023	2022
Firm Retail and Wholesale Sales	$ 839,158	$ 842,737	$ 819,768
Participation and Capacity Sales	53,914	67,399	86,006
Other Sales	147,365	178,701	197,395
Other Operating Revenues	63,688	68,537	72,465
Unearned Revenues	59,512	(85,450)	21,338
Total Operating Revenues	$ 1,163,637	$ 1,071,924	$ 1,196,972

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. 2024 marked the eleventh consecutive year with no overall retail base rate increases and the seventh consecutive year with no wholesale base rate increases. There is no overall base rate increase for wholesale customers yet again in 2025. Retail will have a 2.0% increase in base rates in 2025.

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 $53.0 million, $56.8 million, $33.9 million, and $74.2 million for 12-month periods beginning January 1, 2025, January 1, 2024, February 1, 2023, and February 1, 2022, respectively. The PCA equated to a one-year average bill reduction for wholesale customers compared to base rates of 6.1%, 7.2%, 4.4% and 10.1%, respectively. The PCA also resulted in an average annual decrease for retail customers of 1.0%, 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 decreased $3.5 million, or 0.4%, from $842.7 million in 2023 to $839.2 million in 2024. The decrease was due primarily to a higher wholesale PCA rate for refunds in 2024, which was partially offset by an increase in wholesale energy sales. 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 lower PCA rate for refunds in 2023.

Revenues from Participation and Capacity Sales

Revenues from participation sales decreased from $67.4 million in 2023 to $53.9 million in 2024, a decrease of $13.5 million, or 20.0%. The decrease was due primarily to the participation sales agreements with MEAN for Cooper Nuclear Station and Gerald Gentleman Station which ended December 31, 2023. 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 Other Sales

Other sales consist of sales in SPP's Integrated Market and nonfirm sales to other utilities. Other sales include non-energy transactions, such as auction revenue rights and transmission congestion rights which do not have kWh associated, which therein skews the average cents per kWh sold. Other sales decreased from $178.7 million in 2023 to $147.4 million in 2024, a decrease of $31.3 million, or 17.5%. The decrease was due primarily to a reduction in nonfirm energy sales as a result of the Cooper Nuclear Station planned refueling and maintenance outage and other fossil station outages. 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 Operating Revenues

Other operating revenues consist primarily of revenues from transmission and other miscellaneous revenues. These revenues were $63.7 million, $68.5 million, and $72.5 million in 2024, 2023, and 2022, respectively. The majority of these revenues consist of those received from other SPP transmission customers. The decrease in revenues in 2024 from 2023 was due primarily to the reduction in SPP revenues received from other transmission customers for their share of qualifying transmission upgrade projects of the District. There was also a decrease due to a contract with AECI, which was in effect during 2023 only, for the use of District-owned transmission. 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 deficit 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 deficit 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 deficits 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 deficit 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 deficit is included, in the year accrued, in the net revenues available under the General Resolution to meet debt service requirements for such year. Revenue deficits 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.

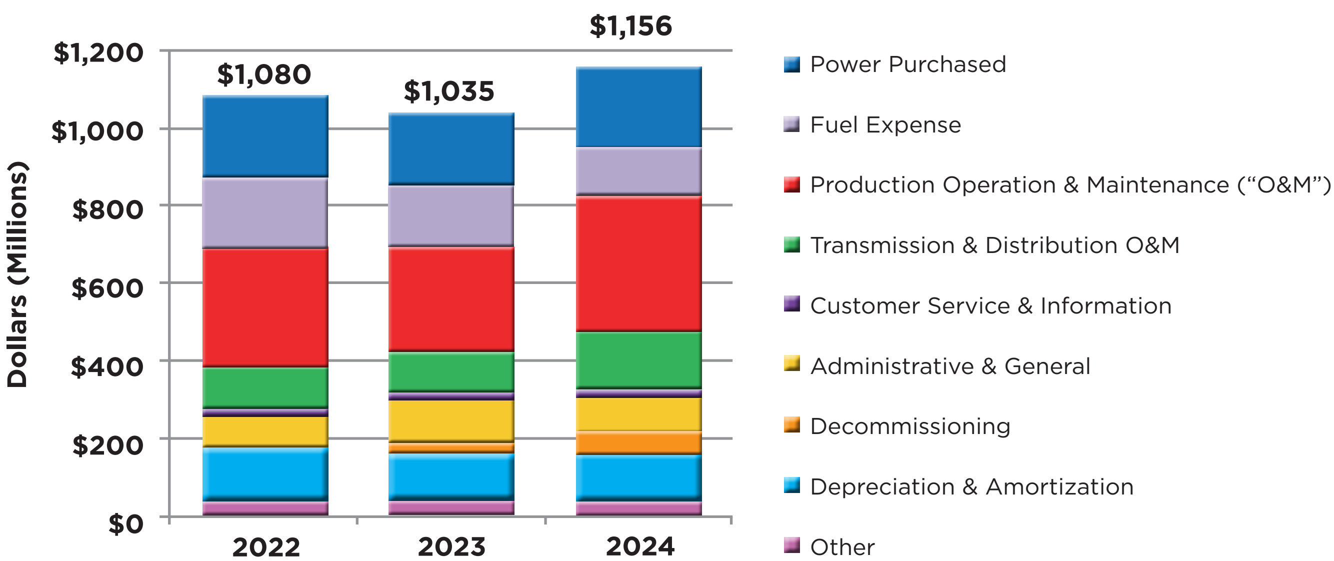
The following table shows the increase (decrease) in revenues from rate stabilization and other regulatory accounts for the years 2024, 2023, and 2022, respectively (in 000's).

	2024	2023	2022
Surplus revenues deferred to future periods	$ (33,793)	$ (67,007)	$ (73,822)
Refunded revenues from prior periods	67,755	76,453	74,160
CNS outage collections	25,550	(25,550)	21,000
CNS reserve	-	(69,346)	-
	$ 59,512	$ (85,450)	$ 21,338

The balance of the regulatory liability for unearned revenues to be applied as credits against revenue requirements in future rate periods was $224.3 million, $258.3 million, and $267.8 million, as of December 31, 2024, 2023, and 2022, respectively.

Operating Expenses

The following chart illustrates operating expenses for the years ended December 31, 2022, through 2024.



Total operating expenses in 2024 were $1,155.5 million, an increase of $120.8 million over 2023. Total operating expenses in 2023 were $1,034.7 million, a decrease of $45.2 million from 2022. The changes were due primarily to the following:

Power purchased expenses were $189.8 million, $179.2 million, and $216.9 million in 2024, 2023, and 2022, respectively. These expenses increased $10.6 million in 2024 over 2023 due primarily to increased quantities and purchases in SPP Integrated Market, higher costs for wind agreements, and higher purchases under the agreements for Kingsley, NC2, and solar, which were partially offset by lower costs for purchases under the agreement for Loup. Power purchased 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.

Fuel expenses were $145.0 million, $161.5 million, and $175.4 million in 2024, 2023, and 2022, respectively. These expenses decreased $16.5 million in 2024 from 2023 due primarily to lower costs for the Gerald Gentleman Station, Sheldon Station, Cooper Nuclear Station, and Beatrice Power Station, which were partially offset by higher costs for the Canaday Station and the CT units. The lower costs for Gerald Gentleman Station, Sheldon Station, Cooper Nuclear Station, and Beatrice Power Station were due primarily to lower generation. The higher costs for the Canaday Station and CT units were due primarily to higher generation. Fuel expenses decreased $13.9 million in 2023 from 2022 due primarily to lower costs for the Beatrice Power Station, Sheldon Station, and Canaday Station, which were partially offset by higher costs for the Cooper Nuclear Station and Gerald Gentleman Station. The lower costs for the Beatrice Power Station and Canaday Station 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 Station and Gerald Gentleman Station were due to primarily higher generation.

Production operation and maintenance expenses were $350.7 million, $275.4, million, and $300.3 million in 2024, 2023, and 2022, respectively. These expenses increased $75.3 million in 2024 over 2023 due primarily to the planned refueling and maintenance outage at Cooper Nuclear Station in 2024 and the outage maintenance at both Gerald Gentleman Station and Beatrice Power Station. 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.

Transmission and distribution operation and maintenance expenses were $128.8 million, $119.8 million, and $116.0 million in 2024, 2023, and 2022, respectively. These costs increased $9.0 million in 2024 over 2023 due primarily to increased costs for salaries and benefits, SPP fees, outside services, and materials and supplies. Transmission and distribution operation and maintenance expenses increased $3.8 million in 2023 over 2022 due primarily to increased costs for salaries and benefits, outside services, and materials and supplies.

Customer service and information expenses were $22.5 million, $18.6 million, and $16.8 million in 2024, 2023, and 2022, respectively. These expenses increased $3.9 million in 2024 over 2023 due primarily to an increase in interest expense on customer deposits, efficiency program payments, and salaries and benefits.

Administrative and general expenses were $103.7 million, $91.1 million, and $83.2 million in 2024, 2023, and 2022, respectively. These expenses increased $12.6 million in 2024 over 2023 due primarily to an increase in salaries and benefits, information technology maintenance and upgrades, and outside services. These expenses increased $7.9 million in 2023 over 2022 due primarily to an increase in salaries and property insurance.

Payments to retail communities were $32.2 million, $32.4 million, and $32.6 million in 2024, 2023, and 2022, respectively. These payments were collected from retail customers in communities with PRO Agreements and remitted to the communities.

Decommissioning expenses were $46.9 million, $18.1, and $0.0 million in 2024, 2023, and 2022, 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 $16.4 million and $30.5 million, respectively, in 2024. Decommissioning expenses increased in 2024 over 2023 due to the commencement of collections in rates for decommissioning costs for Cooper Nuclear Station and an increase in investment income for decommissioning funds. 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 million 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 $125.6 million, $128.4 million, and $128.8 million in 2024, 2023, and 2022, respectively.

Payments in lieu of taxes were $10.4 million, $10.2 million, and $10.2 million in 2024, 2023, and 2022, 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 $62.2 million, $45.7 million, and ($10.2) million in 2024, 2023, and 2022, respectively. The increase of $16.5 million in 2024 over 2023 was due primarily to favorable market returns in 2024. 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.

Debt and Related Expenses

Debt and related expenses were $33.6 million, $30.8 million, and $25.9 million in 2024, 2023, and 2022, respectively. The increase of $2.8 million in 2024 over 2023 and 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.

Change in Net Position

The change in net position was $36.8 million, $52.1 million, and $81.0 million in 2024, 2023, and 2022, respectively. The change in net position in 2024 decreased $15.3 million from 2023 due primarily to lower investment income, lower rate collections for construction from revenue, and increased expense related to capitalized interest. These decreases in changes in net position were partially offset by higher rate collections for principal payments. 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.

CONDENSED STATEMENTS OF CASH FLOWS (in 000's)

For the years ended December 31,	2024	2023	2022
Net Cash Provided by Operating Activities	$ 143,281	$ 289,851	$ 227,742
Net Cash Provided by (Used in) Investing Activities	49,993	(80,580)	93,257
Net Cash Used in Capital and Financing Activities	(203,706)	(214,399)	(336,659)
Net Decrease in Cash and Cash Equivalents	(10,432)	(5,128)	(15,660)
Cash and Cash Equivalents, Beginning of Year	14,001	19,129	34,789
Cash and Cash Equivalents, End of Year	$ 3,569	$ 14,001	$ 19,129

The decrease in net cash provided by operating activities in 2024 from 2023 was due to an increase in payments to suppliers, vendors, and employees, and a decrease in receipts from customers. The increase in net cash provided by investing activities was due to a net sale/maturity position in 2024 compared to a net purchase position in 2023, and an increase in income on investments. The decrease in net cash used in capital and financing activities was primarily due to lower principal payments on revenue bonds and revolving credit agreements, along with higher proceeds from revolving credit agreements, partially offset by higher capital expenditures for utility plant and lower contributions in aid of construction. The increase in net cash provided by operating activities in 2023 over 2022 was due to 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.

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. Debt service coverage ratios were 2.28, 1.62, and 2.31 in 2024, 2023, and 2022, respectively. The debt service coverage increase in 2024 over 2023 was due primarily to a decrease in General System Bonded Debt Service. The decrease in the 2023 debt service coverage ratio over 2022 was due primarily to a decrease in net revenues to establish a $69.3 million regulatory liability for Cooper Nuclear Station costs and a larger amount paid for debt service in 2023. The District's practice is 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+	(negative 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 2025 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"), as hereinafter defined side-by-side credit agreements, 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 $862.9 million, $105.8 million, and $94.4 million in 2024, 2023, and 2022, 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 and the timing of the actual capital project cash flow does not always align with the year budgeted. The District's capital requirements are funded with monies generated from operations, debt proceeds, and other available reserve funds.

Significant capital projects for 2024 included:

- $230.0 million for RICE and generator step-up transformers at Princeton Road Station
- $224.0 million for CTs and generator step-up transformers at Princeton Road Station
- $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, an SPP Notification to Construct ("NTC") 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, an SPP NTC Project
- $10.6 million for Etna 345 kV substation transformer

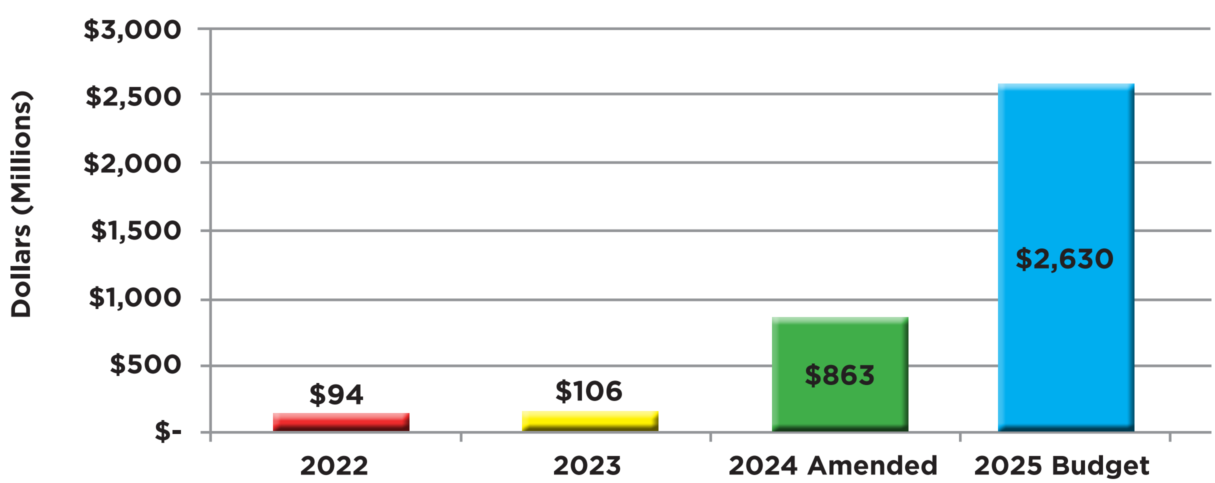
Significant capital projects for 2023 included:
- $9.3 million for Columbus East 115 kV transformer upgrade
- $8.9 million for Gerald Gentleman Station Unit 2 boiler tube surface replacement
- $5.6 million for Sheldon Station condenser and dewatering bins replacement/upgrade
- $5.5 million for Cooper 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 NTC Project

Other authorized capital projects for renewals and replacements to existing facilities and other additions and improvements totaled $132.2 million, $54.9 million, and $50.8 million for 2024, 2023, and 2022, respectively.

The Board-approved budget for capital projects for 2025 is $2,629.7 million. Specific capital projects for 2025 include:
- $1,052.1 million for CTs and associated transmission work at Beatrice Power Station
- $559.1 million for 2025 portion of Princeton Road Station RICE units and associated transmission work
- $496.4 million for 2025 portion of Princeton Road Station CTs and associated transmission work
- $238.5 million for 2025 supplement to 345kV R-Project line, an SPP NTC Project
- $44.3 million for Gothenburg industrial 115kV line and substation project
- $40.2 million for Gothenburg industrial to Crooked Creek 115kV line
- $25.9 million for Etna 345kV substation project
- $23.9 million for Etna Gothenburg industrial 115kV project

The following chart illustrates the Board-approved capital projects for the years ended December 31, 2022, through 2024, including the Board-approved budget for the year ended December 31, 2025.



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 potential future renewable generation in an area of the state that lacks sufficient transmission access. The expected cost of the R-Project is $638.0 million. Additional information on the R-Project, including the status of the 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 an 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 8.5 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 construction phase with an in-service date for both projects of June 2025. The expected combined cost for both projects is $43.5 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 $18.2 million of these NTC costs from other SPP members. The balance of $25.3 million will be recovered through the District's transmission rates.

The District has accepted an 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, material procurement, and easement acquisition phase. Construction activities started in November 2024 for the substation projects and are expected to start in the summer of 2025 for the transmission line, with an expected in-service date for both projects of June 2026. The in-service date for the transformer upgrade at the Hoskins substation is November 2026. The expected combined cost for both projects is $26.8 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 $11.2 million of these NTC costs from other SPP members. The balance of $15.6 million will be recovered through the District's transmission rates.

In October 2024, the SPP Board of Directors approved the 2024 Integrated Transmission Plan ("ITP"). The ITP is an annual planning cycle that assesses near-and long-term economic and reliability transmission needs that produces a 10-year transmission expansion plan. The 2024 ITP includes 89 transmission upgrades, over 2,000 miles of new transmission and nearly 500 miles of transmission rebuilds which approximates nearly $7.7 billion in projects in the SPP region. Of these 89 projects, six have been identified as NTCs for the District. These projects are currently under review; thus, project estimates are not available at this time. Due to timing of the issuance of the 2024 ITP and subsequent NTCs, these projects were not included in the District's original 2025 capital budget but will be incorporated into the District's 2026 through 2031 long-range capital plan when such estimates are available. If the NTCs are accepted by the District, the projects will be base plan funded in accordance with the SPP Tariff.

COOPER NUCLEAR STATION LICENSE RENEWAL PROJECT

The current operating license for Cooper Nuclear Station runs through 2034. In February 2024, the District's Board approved a resolution to proceed with the second license renewal of Cooper Nuclear Station and authorized the expenditure of $56.4 million for the development, submittal, regulatory review, and approval of the licensing renewal, along with early implementation projects. At this time, an additional, approximately $58.4 million is anticipated for additional capital projects associated with the licensing renewal which the Board will act on at a future date. Upon approval of the second license renewal, the Cooper Nuclear Station operating license would be extended an additional 20 years to 2054. Continued operation of Cooper Nuclear Station beyond 2034 will allow the District to maintain a diverse resource mix.

PLANNED NEW GENERATION RESOURCES

The addition of new generation resources to support load growth was approved by the Board as part of the annual budget approval process in 2024 and 2025 and will provide additional capacity to meet the District's resource adequacy requirements in SPP. The battery energy storage project near Ainsworth Wind Energy Facility which was approved by the Board in 2024 is currently on hold pending review of additional battery energy storage technologies.

The District signed a contract in March 2025, for 12 RICE units which will be located at Princeton Road Station (in close proximity to the existing Sheldon Station). The RICE units are expected to provide 216 MW of capacity. In addition, there are two CTs planned at this location which will provide 478 MW of capacity. Contract negotiations are underway for the CTs. Both the RICE and the CTs are planned to be online by the end of 2029.

In addition to the above, the Board approved in 2025 a capital project for an additional 3 CTs to be located at the current Beatrice Power Station site. It is expected that these CTs will provide 717 MW of capacity and will be online at the end of 2030 (at the earliest).

These planned additions maintain diversity and complement the District's overall generation fleet. Furthermore, the resources will have dual-fuel capability.

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. Key disruptions and challenges include significant increases in lead times specifically for procuring transformers and labor disruptions which has increased the demand for specialized supplemental workers. These issues have been attributed to high demand and adverse impacts on production outputs related to insufficient raw materials and labor. As a result, delays and increased cost impacts may be experienced in completing certain projects and work activities. The new Administration has enacted a systematic approach to implementing tariffs with certain trade partners. At this time, the short and long-term impacts of these tariffs to the District, and/or the impacts of these tariffs on the District's customer base, is unknown. The District will continue to monitor any changes and possible impacts in this area.

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. The District is monitoring impacts to IRA and IIJA programs based upon the new Administration priorities and will continue to pursue opportunities 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.

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 54.8% and 61.9% for 2024 and 2023, respectively. Non-carbon energy resources as a percentage of native load sales decreased in 2024 compared to 2023 primarily due to the Cooper Nuclear Station refueling outage in 2024. 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 licensing renewal process at Cooper Nuclear Station, as well as further refine the capital costs needed for the license renewal. Monitor Cooper Nuclear Station operating costs and reevaluate licensing renewal 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.

PHYSICAL AND CYBER SECURITY

The District has physical and cyber 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 0.1% between the third quarter of 2023 and the third quarter of 2024, 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 2.7% increase in real national gross domestic product over the same 12-month period.

According to the Bureau, Nebraska experienced declines in "Agriculture, Forestry, and Fishing" (-30.4%), "Mining, Quarrying, and Oil and Gas Extraction" (-13.5%), "Utilities" (-8.9%), and "Administrative and Support and Waste Management and Remediation Services" (-2.2%). These declines were offset by increases in "Retail Trade" (10.0%), "Arts, Entertainment, and Recreation" (8.6%), "Information" (7.6%), and "Non-Durable Goods Manufacturing" (6.1%).

Despite strong demand for goods and services in 2024, supply constraints lead to higher prices and lost production. These constraints included lack of inputs, due to supply chain disruptions and labor shortages. Low unemployment rates lead to an upward pressure on wages. This upward pressure led to higher rates of inflation in 2024. According to the Consumer Price Index for All Urban Consumers ("CPI-U"), the average annual inflation rate was 2.9% for 2024 and monthly inflation rates were 2.9% and 3.0% for December 2024 and January 2025, respectively.

Nebraska continues 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 2023 value of 2.3% to 2.7% in 2024. This rate was well below the 2024 national average unemployment rate of 3.6%. Nebraska's preliminary, seasonally adjusted unemployment rate was 2.8% in December 2024, up from the revised 2.5% in December 2023. Both numbers were well below the national December seasonally adjusted unemployment rates of 4.1% and 3.8% in 2024 and 2023, respectively. Nebraska's revised December 2024 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,
- 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,
- growing expectations among some large customers for renewable/clean energy supply options, and
- other federal and state legislative and regulatory changes.

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

Opinions

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, 2024 and 2023, 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, 2024 and 2023, 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 Opinions

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 opinions.

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 opinions. 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 25 and 65 through 67 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 68, but does not include the basic financial statements and our auditors' report thereon. Our opinions on the basic financial statements do 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 10, 2025

Statements of Net Position - Business-Type Activities
Nebraska Public Power District
As of December 31, (in 000's)

	2024	2023
ASSETS AND DEFERRED OUTFLOWS		
Current Assets:		
Cash and cash equivalents	$ 3,569	$ 14,001
Investments	711,601	717,284
Receivables, less allowance for doubtful accounts of $514 and $301, respectively	108,206	112,617
Fossil fuels, at average cost	33,504	42,945
Materials and supplies, at average cost	159,107	145,412
Prepayments and other current assets	17,859	20,718
	1,033,846	1,052,977
Special Purpose Funds:		
Construction funds	7,083	12,767
Debt service and reserve funds	87,537	94,194
Employee benefit funds	4,007	4,154
Supplemental decommissioning funds	10,376	-
Decommissioning funds	642,826	634,467
	751,829	745,582
Utility Plant, at Cost:		
Utility plant in service	5,353,129	5,334,121
Less reserve for depreciation	3,225,030	3,182,028
	2,128,099	2,152,093
Construction work in progress	356,528	260,755
Nuclear fuel, at amortized cost	153,227	138,957
	2,637,854	2,551,805
Other Long-Term Assets:		
Regulatory asset for other postemployment benefits	-	17,829
Long-term capacity contracts	103,589	110,718
Unamortized financing costs	3,770	4,537
Equity investments	32,890	27,885
Net other postemployment benefit asset	43,733	18,103
Other	41,097	10,927
	225,079	189,999
Total Assets	4,648,608	4,540,363
Deferred Outflows of Resources:		
Asset retirement obligation	206,861	193,670
Unamortized cost of refunded debt	1,783	2,622
Other postemployment benefits	69,140	87,775
	277,784	284,067
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 4,926,392	$ 4,824,430

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

As of December 31, (in 000's)	2024	2023
LIABILITIES, DEFERRED INFLOWS, AND NET POSITION		
Current Liabilities:		
Revenue bonds, current	$ 78,030	$ 65,110
Revolving credit agreements, current	250,314	109,735
Accounts payable and accrued liabilities	93,745	73,799
Accrued in lieu of tax payments	10,442	10,147
Accrued payments to retail communities	2,621	2,464
Accrued compensated absences	40,425	22,756
Other	30,325	20,577
	505,902	304,588
Long-Term Debt:		
Revenue bonds, net of current	831,507	921,774
Revolving credit agreements, net of current	-	38,035
	831,507	959,809
Other Long-Term Liabilities:		
Asset retirement obligation	860,997	836,937
Other	48,971	42,014
	909,968	878,951
Total Liabilities	2,247,377	2,143,348
Deferred Inflows of Resources:		
Unearned revenues	224,349	258,311
Other deferred inflows	397,485	402,405
	621,834	660,716
Net Position:		
Net investment in capital assets	1,630,720	1,569,236
Restricted	21,570	21,866
Unrestricted	404,891	429,264
	2,057,181	2,020,366
TOTAL LIABILITIES, DEFERRED INFLOWS, AND NET POSITION	$ 4,926,392	$ 4,824,430

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)	2024	2023
Operating Revenues	$ 1,163,637	$ 1,071,924
Operating Expenses:		
Power purchased	189,834	179,175
Production:		
Fuel	144,973	161,478
Operation and maintenance	350,726	275,381
Transmission and distribution operation and maintenance	128,754	119,759
Customer service and information	22,492	18,628
Administrative and general	103,652	91,123
Payments to retail communities	32,164	32,407
Decommissioning	46,917	18,149
Depreciation and amortization	125,572	128,373
Payments in lieu of taxes	10,409	10,191
	1,155,493	1,034,664
Operating Income	8,144	37,260
Investment and Other Income:		
Investment income	59,516	43,529
Other income	2,708	2,128
	62,224	45,657
Change in Net Position Before Debt and Other Expenses	70,368	82,917
Debt and Related Expenses:		
Interest on revenue bonds	42,661	44,042
Allowance for funds used during construction	(9,046)	(7,780)
Bond premium amortization net of debt issuance expense	(10,629)	(12,830)
Interest on revolving credit agreements	10,567	7,360
	33,553	30,792
Change in Net Position	36,815	52,125
Net Position:		
Beginning balance	2,020,366	1,968,241
Ending balance	$ 2,057,181	$ 2,020,366

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)	2024	2023
Cash Flows from Operating Activities:		
Receipts from customers and others	$ 1,076,039	$ 1,134,631
Other receipts	253	356
Payments to suppliers and vendors	(587,655)	(535,053)
Payments to employees	(345,356)	(310,083)
Net cash provided by operating activities	143,281	289,851
Cash Flows from Investing Activities:		
Proceeds from sales and maturities of investments	2,634,709	3,229,348
Purchases of investments	(2,621,554)	(3,319,214)
Income received on investments	38,458	9,432
Change in cash held in special purpose funds	(1,620)	(146)
Net cash provided by (used in) investing activities	49,993	(80,580)
Cash Flows from Capital and Related Financing Activities:		
Proceeds from issuance of revenue bonds	-	161,424
Proceeds from revolving credit agreements	108,296	42,937
Capital expenditures for utility plant	(223,278)	(135,610)
Contributions in aid of construction and other reimbursements	28,458	41,007
Principal payments on revenue bonds	(65,110)	(230,950)
Interest payments on revenue bonds	(42,661)	(44,042)
Interest paid on defeased revenue bonds	-	(1,017)
Principal payments on revolving credit agreements	(5,752)	(43,899)
Interest payments on revolving credit agreements	(7,964)	(7,199)
Other non-operating revenues	4,305	2,950
Net cash used in capital and related financing activities	(203,706)	(214,399)
Net decrease in cash and cash equivalents	(10,432)	(5,128)
Cash and cash equivalents, beginning of year	14,001	19,129
Cash and cash equivalents, end of year	$ 3,569	$ 14,001

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

For the years ended December 31, (in 000's)	2024	2023
Reconciliation of Operating Income to Cash Provided By Operating Activities:		
Operating income	$ 8,144	$ 37,260
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation and amortization	125,572	128,373
Undistributed net revenue - The Energy Authority	(132)	430
Decommissioning, net of customer contributions	24,085	4,366
Amortization of nuclear fuel	29,858	33,026
Changes in assets and liabilities which provided (used) cash:		
Receivables, net	8,248	(23,064)
Fossil fuels	9,441	(8,449)
Materials and supplies	(13,695)	(15,561)
Prepayments and other current assets	(12,368)	(6,934)
Deferred outflows	278	-
Accounts payable and accrued payments to retail communities	15,879	(2,361)
Unearned revenues	(33,962)	(9,447)
Other deferred inflows	(14,684)	116,624
Other liabilities	(3,383)	35,588
Net cash provided by operating activities	$ 143,281	$ 289,851

Supplementary Non-Cash Capital Activities:		
Change in utility plant additions in accounts payable	$ 9,678	$ (1,930)

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)	2024	2023
Assets:		
Cash and cash equivalents	$ 20,368	$ 9,743
Receivables:		
Investment income	835	792
Investments	366,306	347,681
Total Assets	387,509	358,216
Liabilities:		
Payables:		
Benefits - healthcare	122	108
Benefits - life insurance	59	60
Investment expense	150	126
Professional, administrative and other expenses	47	25
Total liabilities	378	319
Net Position - Restricted for Other Postemployment Benefits	$ 387,131	$ 357,897

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)	2024	2023
Additions:		
Contributions		
Employer	$ 2,406	$ 2,850
Investment Income:		
Net appreciation in fair value of investments	38,113	41,457
Interest, dividends and other income	7,747	6,890
Total investment income	45,860	48,347
Less: Investment expenses	(1,063)	(1,052)
Net investment income	44,797	47,295
Total additions	47,203	50,145
Deductions:		
Health care benefits	17,466	17,757
Life insurance benefits	247	170
Professional, administrative and other expenses	256	231
Total deductions	17,969	18,158
Change in Net Position	29,234	31,987
Net Position - Restricted for Other Postemployment Benefits		
Beginning balance	357,897	325,910
Ending balance	$ 387,131	$ 357,897

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 2.0% and 1.9% for the years ended December 31, 2024, and 2023. The District had fully depreciated utility plant, primarily related to Cooper Nuclear Station, which was still in service of $1,643.2 million and $1,606.3 million as of December 31, 2024, and 2023, respectively.

The District's retail service territory includes 79 municipal-owned distribution systems within the State of Nebraska two tribal entities 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 $10.3 million and $8.1 million in 2024 and 2023, respectively, which was included in depreciation and amortization expense. These utility plant additions, which were fully amortized, totaled $237.1 million and $229.2 million as of December 31, 2024 and 2023, 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, the TRCA, or the side-by-side agreement 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 2.5% to 5.8%. For construction financed on a short-term basis, the rate was 4.0% and 4.5% for 2024 and 2023, 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, 2024, and 2023 and activity for the years then ended (in 000's):

	2024	2023
Unearned revenues, beginning of year	$ 258,311	$ 267,758
Surpluses	33,793	67,006
Use of prior period rate stabilization funds in rates	(67,755)	(76,453)
Unearned revenues, end of year	$ 224,349	$ 258,311

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 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 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.

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

The other regulatory liabilities relate to timing differences in revenue and expense recognition between rates and GASB guidance.

In 2024, the District began segregating amounts in excess of the Nuclear Regulatory Commission ("NRC") minimum requirement. Funds collected would be used for license termination costs and to return Cooper Nuclear Station site to a useable condition. 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.

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 was amortized through revenue during 2024, the year of the outage.

The following table summarizes the balance of Other deferred inflows of resources as of December 31, 2024, and 2023 (in 000's):

	2024	2023
Non-nuclear decommissioning collections	$ 79,525	$ 65,660
DOE settlements	77,421	78,312
Unrealized OPEB gains	69,519	78,284
Cooper Nuclear Station reserve	69,346	69,346
Nuclear fuel disposal collections	62,782	57,103
Settlements for termination of agreements	17,358	21,725
Other regulatory liabilities	11,158	6,425
Nuclear supplemental decommissioning	10,376	-
Cooper Nuclear Station outage collections	-	25,550
	$ 397,485	$ 402,405

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 consists 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 reference 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, 2024 and 2023, respectively.

GASB Statement No. 101, *Compensated Absences,* was issued in June 2022 and implemented in 2024. The District had recognized liabilities for unused vacation benefits earned by employees in years prior to 2024. This Statement required the recognition of additional liabilities for certain compensated absences, like sick leave, regardless of whether the sick leave benefit is vested or not vested. 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. This Statement resulted in the recognition of an additional liability with a corresponding regulatory asset on the District's financial statements for non-vested employee sick leave benefits in the amount of $14.8 million as of December 31, 2024. As these amounts were considered immaterial to the District's financial position, there were no restatements made for prior periods.

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.

GASB Statement No. 103, *Financial Reporting Model Improvements,* was issued in April 2024. The objective of this Statement is to improve key components of the financial reporting model to enhance its effectiveness in providing information that is essential for decision making and assessing a government's accountability. For business-type activities like the District, this Statement provides clarity regarding what information should be presented in the MD&A, including definitions of subsidies, operating and non-operating revenues and expenses, and changes in certain financial statement presentation requirements. The requirements of this Statement are effective for the fiscal years beginning after June 15, 2025.

GASB Statement No. 104, *Disclosure of Certain Capital Assets,* was issued in September 2024. The objective of this Statement is to provide users of government financial statements with essential information about certain types of capital assets. The Statement requires certain types of capital assets to be disclosed separately by major class of underlying asset in the capital assets note disclosures. Lease assets recognized in accordance with Statement No. 87, intangible right-to-use-asset recognized in accordance with Statement No. 94, subscription assets recognized in accordance with Statement No. 96, and intangible assets other than those three types are to be disclosed separately by major class. The requirements of this Statement are effective for the fiscal years beginning after June 15, 2025.

2. CASH AND INVESTMENTS:

Investments are recorded at fair value with the changes in the fair value of investments reported as Investment income in the accompanying Statements of Revenues, Expenses, and Changes in Net Position. The District had an unrealized net loss of $1.2 million in 2024 and an unrealized net gain of $11.4 million in 2023, 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):

	2024		2023	
	Fair Value	Weighted Average Maturity (Years)	Fair Value	Weighted Average Maturity (Years)
U.S. Treasury and government agency securities ..	$ 1,054,580	4.2	$ 1,007,808	4.7
Corporate bonds	213,713	6.2	218,505	11
Municipal bonds	21,303	7.1	10,386	14
Cash and cash equivalents	177,403	0.1	240,168	0.0
Total cash and investments	$ 1,466,999		$ 1,476,867	
Portfolio weighted average maturity		4.0		4.9

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.

	2024	2023
Revenue funds - Cash and cash equivalents	$ 3,569	$ 14,001
Revenue funds - Cash equivalents in investments	156,507	197,765
Revenue funds - Investments	555,094	519,519
	$ 715,170	$ 731,285

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.

	2024	2023
Construction funds - Investments	$ 7,083	$ 12,767

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 50.0% of the maximum amount of interest accrued in the current or any future year in the Primary account. Such amounts totaled $21.6 million and $22.0 million as of December 31, 2024, and 2023, 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 accounts totaled $51.8 million and $51.5 million as of December 31, 2024, and 2023.

	2024	2023
Debt service and reserve funds - Cash and cash equivalents	$ -	$ 105
Debt service and reserve funds - Investments	87,537	94,089
	$ 87,537	$ 94,194

The Employee benefit funds consist of a self-funded hospital-medical benefit plan for active employees only as of December 31, 2024, and 2023. The District pays 87.0% and 86.0% of the hospital-medical premiums with the employees paying the remaining 13.0% and 14.0% of the cost of such coverage for the years 2024 and 2023, respectively.

	2024	2023
Employee benefit funds - Cash and cash equivalents	$ 4,007	$ 4,154

The Supplemental decommissioning funds are for costs in excess of NRC minimum funding requirements for license termination and to return the site to useable condition. The Supplemental decommissioning funds are held by outside trustees or custodians in compliance with the decommissioning funding plans approved by the Board. Collections from customers in rates are used to fund this account.

	2024	2023
Supplemental decommissioning funds - Cash and cash equivalents	$ 10,376	$ -

The Decommissioning funds are utilized to account for the investments held to fund the estimated NRC required costs 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.

	2024	2023
Decommissioning funds - Cash and cash equivalents	$ 2,944	$ 19,027
Decommissioning funds - Investments	639,882	615,440
	$ 642,826	$ 634,467

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, 2024, and 2023.

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):

	2024			
	Level 1	Level 2	Level 3	Total
Revenue, special purpose funds, and supplemental decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 649,714	$ -	$ 649,714
Cash and cash equivalents	174,459	-	-	174,459
Decommissioning funds:				
U.S. Treasury and government agency securities	-	404,866	-	404,866
Corporate bonds	-	213,713	-	213,713
Municipal bonds	-	21,303	-	21,303
Cash and cash equivalents	2,944	-	-	2,944
	$ 177,403	$1,289,596	$ -	$1,466,999

	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

4. UTILITY PLANT:

Utility plant activity for the year ended December 31, 2024, was as follows (in 000's):

	December 31, 2023	Increases	Decreases	December 31, 2024
Nondepreciable utility plant:				
Land and improvements	$ 80,137	$ 89	$ (2,822)	$ 77,404
Construction in progress	260,755	185,390	(89,617)	356,528
Total nondepreciable utility plant	340,892	185,479	(92,439)	433,932
Nuclear fuel*	138,957	44,128	(29,858)	153,227
Depreciable utility plant:				
Generation - Fossil	1,721,672	10,783	(1,239)	1,731,216
Generation - Nuclear	1,375,541	8,117	(50,923)	1,332,735
Transmission	1,481,478	40,982	(3,695)	1,518,765
Distribution	278,656	20,168	(10,393)	288,431
General	396,637	13,735	(5,794)	404,578
Total depreciable utility plant	5,253,984	93,785	(72,044)	5,275,725
Less reserve for depreciation	(3,182,028)	(115,046)	72,044	(3,225,030)
Depreciable utility plant, net	2,071,956	(21,261)	-	2,050,695
Utility plant activity, net	$ 2,551,805	$ 208,346	$ (122,297)	$ 2,637,854

* Nuclear fuel decreases represented amortization of $29.9 million.

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.

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 $71.0 million and $66.5 million as of December 31, 2024 and 2023, respectively. The unamortized amount of the plant capacity contract was $106.3 million and $111.1 million as of December 31, 2024, and 2023, respectively, of which $4.4 million was included in Prepayments and other current assets as of December 31, 2024, and 2023. The District's share of NC2 working capital was also included in Prepayments and other current assets and was $8.4 million and $8.0 million as of December 31, 2024 and 2023, 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 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 $82.8 million and $80.5 million as of December 31, 2024 and 2023, respectively. The unamortized amount of the Central capacity contract was $3.9 million and $6.2 million as of December 31, 2024, and 2023, respectively, of which $2.3 million was included in Prepayments and other current assets as of December 31, 2024, and 2023.

The District has an agreement whereby Central makes available all the production of the facility and the District pays all costs of operating and maintaining the facility plus a charge based on the amount of energy delivered to the District. Power purchased costs related to Central were $2.2 million and $1.7 million in 2024 and 2023, respectively.

6. EQUITY INVESTMENTS:

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 was 17.65% as of December 31, 2024 and 2023. In addition to the District, the following utilities have interests of 17.65% each as of December 31, 2024: American Municipal Power, Inc.; JEA (Florida); Grand River Dam Authority; 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, 2024: City Utilities of Springfield, Missouri, and Gainesville Regional Utilities (Florida). The Municipal Energy Authority of Georgia terminated its interest in TEA on April 1, 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. Grand River Dam Authority joined with interest in TEA on July 1, 2024 which decreased the District's interest to 17.65% on July 1, 2024.

Such investment was $32.8 million and $27.9 million as of December 31, 2024 and 2023, 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 and are subordinate to the District's obligation to pay debt service on 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, 2024, 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 guaranty. The term of this guaranty is generally indefinite, but the District has the right to reduce and/or terminate its guaranty obligation by providing advanced notice to the beneficiaries thereof. Such termination of its guaranty obligation 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, 2024, and 2023.

The District also has an investment in TEA Solutions ("TSI"), a for-profit corporation co-located with TEA and headquartered in Jacksonville, Florida. TSI is a national energy marketing and risk management services company that provides portfolio management, regional transmission organization trading, bilateral power trading, power supply management, natural gas trading services, and advanced technology systems to community-owned utilities. The District joined with interest in TSI on May 31, 2024. The District's interest was 20.0% as of December 31, 2024. In addition to the District, the following utilities have interests of 20.0% each as of December 31, 2024: American Municipal Power, Inc.; City Utilities of Springfield, Missouri, JEA (Florida); and Santee Cooper.

Such investment was $0.1 million as of December 31, 2024. The District accounts for its investment in TSI under the equity method of accounting and does not provide any guarantees to TSI for trade collateral.

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, 2024, and 2023, and debt activity for 2024 (in 000's):

	Total Debt at December 31, 2023	Increases	Decreases	Total Debt at December 31, 2024	Long-Term Debt at December 31, 2024	Current Liabilities at December 31, 2024
Revenue bonds	$ 986,884	$ -	$ (77,347)	$ 909,537	$ 831,507	$ 78,030
Revolving credit agreements	147,770	108,296	(5,752)	250,314	-	250,314
Total debt activity	$ 1,134,654	$ 108,296	$ (83,099)	$ 1,159,851	$ 831,507	$ 328,344

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

General Revenue Bonds

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, 2024 and 2023, respectively.

There were outstanding principal amounts aggregating $2.9 million and $3.4 million from legal defeasances of General Revenue Bonds, 2017 Series A, as of December 31, 2024 and 2023, 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, 2024, are as follows (in 000's):

Year	Debt Service Payments	Principal Payments
2025	$ 117,905	$ 78,030
2026	99,318	62,815
2027	97,067	63,295
2028	231,194	203,860
2029	66,201	44,990
2030-2034	282,949	209,005
2035-2039	158,607	128,285
2040-2044	61,321	54,455
2045	2,809	2,675
Total Payments	$ 1,117,371	$ 847,410

The fair value of outstanding General Revenue Bonds was determined using currently published rates. The fair value was estimated to be $861.5 million and $956.9 million as of December 31, 2024 and 2023, 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, for 2023, the District's loan commitment was restricted to a maximum of 25.0% 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. Per the First Amendment to TERCA on August 15, 2024, the District's loan commitment is now restricted for 2024 to a maximum of 25.0% capitalization instead of 25.0% of the debt. This 25.0% capitalization is defined as 25.0% of the sum of total revenue bonds outstanding, total variable rate debt outstanding, and total net position. As of December 31, 2024, the capitalization ratio of the District was 7.8%, which is below the maximum of 25.0%.

The District had an outstanding balance under the TERCA of $70.4 million and $38.0 million as of December 31, 2024, and 2023, respectively. As such, the remaining credit available under TERCA was $79.6 million and $112.0 million as of December 31, 2024, and 2023, 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 on August 15, 2024, 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 any of the TERCA, the TRCA, or the hereinafter defined side-by-side credit agreements 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, for 2023, the District's loan commitment was restricted to a maximum of 25.0% of the Debt of the District represented by outstanding bonds issued. The District had outstanding bonds of $912.5 million as of December 31, 2023. Thus, the maximum allowed TRCA borrowings as of December 31, 2023, were capped at $228.1 million. Per the Third Amendment to TRCA on July 26, 2024, the loan commitment was increased to $300.0 million, and the 25% debt limit was eliminated.

The District had outstanding balances under the TRCA of $179.9 million and $109.7 million, as of December 31, 2024 and 2023, respectively. For 2023, 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 25.0% of outstanding bonds, was $118.4 million. For 2024, the remaining credit available under TRCA is $120.1 million due to the increased commitment amount of $300.0 million. 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 amended on July 26, 2024, with a termination date of July 25, 2025.

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 any of the TRCA, the TERCA, or the hereinafter defined side-by-side credit agreements 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-".

Side-By-Side Credit Agreements

On October 17, 2024, the District entered into a revolving credit agreement ("SBSRCA") with a commercial bank and a reimbursement agreement ("SBSRA") with a commercial bank. The SBSRCA and the SBSRA are herein the side-by-side credit agreements. The SBSRCA provides for loan commitments to the District up to an aggregate amount not to exceed $500.0 million. The SBSRA provides credit support for a commercial paper program supported by a letter of credit issued by the commercial bank pursuant to the SBSRCA. The District is authorized to issue up to $500.0 million of commercial paper notes. A $544.4 million letter of credit expiring October 17, 2027, is maintained with the commercial bank to support the sale of commercial paper notes. Both the SBSRCA and the SBSRA each have a maximum commitment of $500.0 million, but the amounts drawn under the side-by-side credit agreements cannot exceed $500.0 million in the aggregate. Debt incurred under the SBSRCA or commercial paper issued by the District can be either taxable or tax-exempt debt, based on the underlying use of funds.

The District has not borrowed any funds under the SBSRCA nor issued any commercial paper as of December 31, 2024. Any future outstanding amounts under the SBSRCA and commercial paper are anticipated to be retired by collections through electric rates and the issuance of General Revenue Bonds. The side-by-side credit agreements were incepted on October 17, 2024, with respective termination dates of October 17, 2027, unless such date is extended or earlier terminated.

The obligation of the District to pay principal, interest, bank fees and expenses pursuant to the side-by-side credit agreements during the term of the side-by-side credit agreements is payable from the Pledged Property subject and subordinate to the pledge of the Pledged Property to the payment of the General Revenue Bonds. However, if any of the TRCA, TERCA, SBSRCA or SBSRA is converted to a term loan, the payment obligation of the District on the SBSRCA or the SBSRA, as applicable, would be on a parity with the District's obligation to pay the General Revenue Bonds.

Each of the side-by-side credit agreements define 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, 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	2024	2023
General Revenue Bonds:			
2010 Series A Taxable Build America Bonds:			
Serial Bonds: 2024	4.73%	$ -	$ 5,695
Term Bonds: 2025–2029	5.323%	27,985	27,985
2030–2042	5.423%	54,190	54,190
2012 Series B:			
Serial Bonds: 2024–2032	2.875% - 5.00%	4,465	4,945
Term Bonds: 2033–2036	3.625%	2,320	2,320
2037–2042	3.625%	4,155	4,155
2015 Series A-1 Serial Bonds 2024–2034	3.00% - 5.00%	92,100	104,745
2016 Series A:			
Serial Bonds: 2024–2035	3.125% - 5.00%	44,395	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 2024–2035	5.00%	36,770	41,730
2016 Series D:			
Serial Bonds: 2024–2035	3.00% - 5.00%	14,625	15,620
Term Bonds: 2036–2040	5.00%	9,505	9,505
2041–2045	5.00%	12,140	12,140
2016 Series E Taxable Serial Bonds 2024–2033	2.652% - 3.567%	43,790	47,980
2017 Series A Serial Bonds 2024–2027	3.00% - 5.00%	1,200	1,775
2017 Series B Serial Bonds 2024–2027	5.00%	18,030	23,480
2019 Series A Serial Bonds 2024–2034	5.00%	25,705	27,695
2019 Series B-1 Taxable Serial Bonds 2024–2028	2.331% - 2.593%	44,980	56,705
2019 Series B-2 Taxable Serial Bonds 2024–2028	2.331% - 2.593%	10,595	12,190
2021 Series A Serial Bonds 2024–2039	5.00%	65,315	68,140
2021 Series B Serial Bonds 2028–2040	5.00%	50,580	50,580
2021 Series C Serial Bonds 2024–2031	5.00%	43,745	45,035
2021 Series D:			
Serial Bonds: 2024–2026	5.00%	1,130	2,555
Term Bonds: 2041–2043	4.00%	18,720	18,720
2023 Series A Term Bonds 2028	5.00%	149,640	149,640
Total par amount of General Revenue Bonds		847,410	912,520
Unamortized premium net of discount		62,127	74,364
		909,537	986,884
Less – current maturities of General Revenue Bonds		(78,030)	(65,110)
Long-term General Revenue Bonds		$ 831,507	$ 921,774

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 $10.4 million and $10.2 million for December 31, 2024 and 2023, 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 represent the amounts collected in rates and interest income on decommissioning funds.

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

Description	2024	2023
Cooper Nuclear Station license termination costs	$ 840,459	$ 816,852
GGS and Sheldon ash landfills	11,701	11,469
Ainsworth	7,837	7,616
Underground storage tanks	1,000	1,000
	$ 860,997	$ 836,937

The District is required by the 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 an external study completed in 2023. The 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. 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. Rates in the consumer price index for all urban consumers ("CPI-U") were used to adjust these obligations for inflation, as the costs in the study were in 2023 dollars. The inflation rate used was 2.9% for the year 2024. No consumer price adjustment was required for the 2023 obligation amount as the study was in 2023 dollars. Nuclear decommissioning fund balances were $642.8 million and $634.5 million as of December 31, 2024, and 2023, respectively. These funds exceeded the NRC's required funding provisions for nuclear decommissioning. A supplemental decommissioning fund was established during 2024 for decommissioning costs in excess of NRC minimum funding requirements which had a balance $10.4 million as of December 31, 2024.

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 2024 and 2022 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 2.9% and 3.6% for 2024 and 2023, 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 $0.7 million and $0.9 million for 2024 and 2023, 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 2024 and 2023 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 $1.6 million and $1.5 million for 2024 and 2023, 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 2,030 and 1,989 active Plan members as of December 31, 2024, and 2023, 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 $20.2 million and $19.2 million for 2024 and 2023, respectively. The District's matching contributions were $18.1 million and $17.4 million for 2024 and 2023, respectively. Total contributions of $2.0 million and $1.8 million were accrued in accounts payable and accrued liabilities as of December 31, 2024 and 2023, respectively.

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

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

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

Employees may also contribute to an eligible deferred compensation plan which is intended to meet the requirements of Code Section 457(b) ("457(b) Plan"). The 457(b) Plan is a defined contribution plan which permits Pre-tax and Roth elective deferral contributions. The Plan does not provide for a District match but does permit discretionary non-elective contributions by the District. There were 672 and 643 active Plan members as of December 31, 2024 and 2023, 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 participant contributions to the 457(b) Plan were $3.2 million and $3.0 million for 2024 and 2023, 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 2024 of $4,456 and $2,228 for pre-age 65 and post-age 65 retirees, respectively. In November 2024, the Board authorized the President and Chief Executive Officer of the District to approve and authorize the annual adjustments to the RRA. The President and Chief Executive Officer authorized an increase in these annual amounts to $4,590 and $2,295 for 2025, respectively. The District also provides a postemployment death benefit of $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:

	2024	2023
Active employees	1,959	1,927
Inactive employees or beneficiaries in retirement status	1,486	1,473
Inactive employees or beneficiaries in long-term disability status	42	41
Total employees covered by benefit terms	3,487	3,441

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

	2024	2023
Active employees	1,959	1,927
Inactive employees in retirement status	1,358	1,335
Inactive employees in long-term disability status	46	46
Total employees covered by benefit terms	3,363	3,308

Contributions
The Board annually approves the funding for the Plan, which has a minimum funding requirement of the actuarially-determined annual required contribution (“ADC”) to achieve full funding status on or before December 31, 2033. Effective, January 1, 2023, the Board approved a change in the funding policy that excess Plan assets can be used when calculating the ADC. The District did not reduce the ADC for excess Plan assets for 2024 and 2023. The District OPEB contributions were $2.4 million and $2.9 million for 2024 and 2023, 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 $0.7 million and $0.6 million for 2024 and 2023, respectively. As these contributions were from inactive members, they were reported as a reduction of benefit expenses. Members do not contribute to the cost of the life insurance benefits.

B. *Net OPEB (Asset)/Liability –*
The District’s net OPEB asset was measured as of January 1, 2024, and January 1, 2023. 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, 2024, actuarial valuation were based on the results of an actuarial experience study completed during 2023. The actuarial assumptions and methods used in the January 1, 2023, actuarial valuation were based on the results of an actuarial experience study completed during 2018. The total OPEB liability in the January 1, 2024, and 2023, 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: 7.6% initial for 2024, ultimate 4.5% Post-Medicare: 8.5% initial for 2024, ultimate 4.5% Pre-Medicare: 6.9% initial for 2023, ultimate 4.5% Post-Medicare: 7.3% initial for 2023, ultimate 4.5%
RRA increase rate	3.0%
Administrative cost trend	3.0%
Inflation	2.3% for 2024 and 2.4% for 2023
Salary increases	4.0%
Investment rate of return	6.25% for 2024 and 2023, net of investment expense, including inflation
Discount rate	6.25% for 2024 and 2023, 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	For 2024, 80% of males and 50% 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 2023, 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	2024	2023
Equity and Real Estate	70%	7.3%	7.6%
Fixed Income	30%	4.2%	4.3%
Total	100%	6.7%	6.9%

Discount Rate

The discount rate used to measure the total OPEB liability was 6.25% for the actuarial valuations as of January 1, 2024 and 2023, 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, 2024, and the changes during this period, based on the valuation measurement date of January 1, 2024 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB (Asset) Liability (a-b)
Balances at January 1, 2023	$ 307,404	$ 325,910	$ (18,506)
Changes for the year:			
Service cost	2,263	-	2,263
Interest	18,802	-	18,802
Differences between expected and actual experience	1,369	-	1,369
Changes of assumptions	1,825	-	1,825
Contributions - employer	-	2,850	(2,850)
Net investment income	-	47,295	(47,295)
Benefit payments	(17,927)	(17,927)	-
Administrative expense	-	(231)	231
Net changes	6,332	31,987	(25,655)
Balances at January 1, 2024	$ 313,736	$ 357,897	$ (44,161)

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

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, 2024 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB (Asset)/Liability	$ (7,007)	$ (44,160)	$ (75,459)

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

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 6.6% initial to 3.5% ultimate, Post-Medicare ranging from 7.5% initial to 3.5% ultimate) or 1-percentage-point higher (Pre-Medicare ranging from 8.6% initial to 5.5% ultimate, Post-Medicare ranging from 9.5% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 7.6% initial to 4.5% ultimate, Post-Medicare ranging from 8.5% initial to 4.5% ultimate) at the measurement date of January 1, 2024 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB (Asset)/Liability	$ (73,694)	$ (44,160)	$ (9,300)

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

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 $13.4 million for 2024, 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 $2.4 million for 2024.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2024 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ 1,173	$ 24,723
Changes in assumptions	12,474	6,898
Difference between actual and expected earnings	53,087	37,898
Contributions made during the year ended December 31, 2024	2,406	-
	$ 69,140	$ 69,519

The deferred outflows of resources related to the contributions made during the year ended December 31, 2024, will be recognized in the actuarial valuation with a measurement date of January 1, 2025. 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
2025	$ (6,147)
2026	1,527
2027	9,768
2028	(6,724)
2029	(1,665)
2030	456
Total	$ (2,785)

OPEB expense was negative $9.1 million for 2023, as calculated under the GASB guidance, which was largely due to the expected investment 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, were 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

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 $71.3 million at December 31, 2024. 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 2032 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 material. The District has adequate uranium supplies in inventory through the 2026 core reload. These commitments for nuclear fuel material and services including fabrication have combined estimated future payments of $180.8 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 149 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 2024. The annual minimum future payments are approximately $35.5 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 433 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 153 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 2024 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 –*

Retail Agreements

The District entered into long-term PRO Agreements with 79 municipalities in Nebraska and two tribal entities in South Dakota for the operation of certain retail electric distribution systems. Seventy-eight of these municipalities in Nebraska and two tribal entities in South Dakota have renewed or enhanced their PRO Agreements with terms of 20 or 25 years expiring between 2038 and 2049. These 80 retail PRO Agreement customers represented 76.9% of retail revenues for 2024. The remaining PRO Agreement which expires in 2031 is being actively worked for renewal. These PRO Agreements obligate the District to make payments based on gross revenues from the municipalities and pay for normal system additions during the term of the agreement.

Wholesale Power Contracts

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 36 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 45th percentile level (the "Performance Standard Percentile") of the power costs of U.S. utilities for such year as listed in the CFC Data. The 2016 Contracts 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 2019 to 2023 set forth in the CFC Data:

CFC Data	
Year	Percentile
2019	29.5%
2020	23.2%
2021	12.4%
2022	11.7%
2023	16.7%

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 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 potential 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 for 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 $498.3 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 $166.3 million through December 31, 2024, 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.

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 current 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 to begin 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 2025. Settlements from the DOE for damages totaled $145.7 million for the years 2009 through 2024. 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 $77.4 million and $78.3 million as of December 31, 2024 and 2023, respectively.

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. The balance in the regulatory liability was $62.8 million and $57.1 million as of December 31, 2024 and 2023, respectively.

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 $165.9 million per unit owned in the event of any nuclear incident involving any licensed facility in the nation, with a maximum assessment of $24.7 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, 2024, Cooper Nuclear Station was in the Licensee Response Column 1, which is the 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, 2024 and was completed on November 4, 2024. During this outage, in addition to replacing 180 fuel assemblies and conducting routine maintenance and inspections, the team performed inspections of the main low pressure turbine number one, replaced one neutral bushing and flexible links on the parallel rings of the main generator and replaced the large bore piping in the main condenser B. The next refueling and maintenance outage is currently planned for the fall of 2026.

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 eliminated through revenue recognition during the 2024 outage year and was $25.6 million as of December 31, 2023.

F. *Environmental –*

Water

The Federal Clean Water Act contains requirements for effluent limitations relating to the discharge of any pollutant and for environmental impacts of cooling water intake structures. The NDEE establishes the compliance requirements through the issuance of National Pollutant Discharge Elimination System ("NPDES") permits. The NDEE issued NPDES permits to Gerald Gentleman Station, Sheldon Station, Cooper Nuclear Station, Beatrice Power Station, Canaday Station, and the North Platte Office Building.

Water – CWA Section 316

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 U.S. Environmental Protection Agency 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 at 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 be installed by July 1, 2025, and modifications for Gerald Gentlemen Station must be installed by September 1, 2026. The current estimated costs for this technology at Cooper Nuclear Station and Gerald Gentleman Station are $13.3 million and $7.2 million, respectively.

Water – Effluent Limitation Guidelines ("ELG") Rule

On January 2, 2016, the final Steam Electric Power Plant ELG became effective. The rule revises the technology-based ELG and standards that would strengthen the existing controls on discharges from steam electric power plants. It also set the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The rule establishes new or additional requirements for wastewater streams from the following processes 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 ELG rule are Cooper Nuclear Station, Gerald Gentleman Station, Sheldon Station, and Canaday Station, this rule change only impacts Sheldon Station. Sheldon Station will be required to comply with the ELG rule for its bottom ash transport water. On August 31, 2020, the EPA Administrator signed the Steam Electric Reconsideration Rule, which modified the existing ELG 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 ELG rule is December 31, 2025.

On May 9, 2024, the EPA released the "Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category" final rule. The rule requires a zero-discharge system by December 31, 2029, at Sheldon Station. The District plans to install a zero-discharge system to comply with the final rule.

Air – Greenhouse Gas rules

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. With a change in Administration, the EPA issued the Affordable Clean Energy ("ACE") rule on June 19, 2019, that replaced the CPP rule. 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) and remanded the rule back to EPA.

On May 9, 2024, the EPA published the final rule for new greenhouse gas regulations for electric generation facilities which utilize natural gas, coal, or oil. The final regulations require varying compliance obligations depending on equipment type, fuel type, capacity factor, and remaining life of the specific generating unit. Coal plants scheduled to operate beyond 2039 would require 90.0% carbon capture and sequestration to be installed and operating by 2032. Carbon sequestration is also required by 2032 for new baseload natural combustion turbine gas plants. Co-firing with natural gas is an option for certain coal plants. On December 6, 2024, the U.S. Court of Appeals for D.C. Circuit heard oral arguments over challenges to the final rule.

With the change in Administration, the Department of Justice ("DOJ") filed a motion seeking to hold the greenhouse gas power plant litigation in abeyance for a period of 60 days on February 5, 2025. The motion was granted on February 19, 2025. The stay was requested to give EPA time to review the rule and determine the appropriate course of action to take on the rule. It is expected the EPA will request a remand of the rule to make modifications to the requirements.

Air- 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 Particulate Matter (PM10-PM2.5), Sulfur Dioxide ("SO_2"), and Nitrogen Oxides ("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 were not 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.

On September 6, 2023, the NDEE public noticed the draft State Implementation Plan ("SIP") for the second planning period and held a public hearing on November 9, 2023. On August 20, 2024, the NDEE submitted the final SIP to the EPA. The final SIP does not recommend any additional controls for the second implementation period (ending in 2028).

In an unanticipated action, on August 1, 2024, the EPA responded to a voluntary remand from Regional Haze. First Planning period with a proposed Federal Implementation Plan ("FIP") directing the installation of SO_2 controls at Gerald Gentleman Station. The District responded to the proposed action on October 30, 2024, stating there is no legal or factual basis for the FIP. There has been no response from EPA.

Air - 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 May 7, 2024, the EPA issued the final 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. The final rule reduced the filterable Particulate Matter ("PM") emission limit for coal-fired facilities and requires the facilities to install continuous PM monitors. Stack testing, which is not continuous monitoring, at Gerald Gentleman Station and Sheldon Station has indicated that the District should be able to comply with the proposed lower PM emission limits.

Air - 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 SO_2 and 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.

Air - 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.

Waste – Coal Combustion Residuals ("CCR") Legacy Rule

The EPA issued the CCR rule in 2015. The rule developed regulations for CCR landfills and surface impoundments designed to prevent contamination of groundwater and air pollution. In 2024, the EPA issued amendments to the CCR regulations called the legacy CCR surface impoundments rule. This rule regulated legacy surface impoundments, which are inactive surface impoundments at inactive facilities. NPPD does not have any legacy surface impoundments. However, the rule also began to regulate CCR Management Units ("CCRMUs"), which are areas at existing coal plants in which CCR was disposed in an unregulated landfill. NPPD has CCRMUs at Sheldon Station and Gerald Gentleman Station.

Under the legacy CCR surface impoundments rule, facilities which may have CCRMUs must first identify potential areas where CCR landfills or impoundments may be located and then complete a two-part Facility Evaluation Report which further defines the exact location of the buried CCR. The facility must then develop a groundwater monitoring program for the CCRMUs along with developing a plan for closure and post-closure care and addressing corrective actions. NPPD anticipates that the groundwater monitoring network at Gerald Gentleman Station will be adequate but the network at Sheldon Station will need to be extended.

Endangered Species Act and Federally Protected Species

To construct the R-Project, 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. The District started construction activities in July of 2019.

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 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. Following the court's decision, the District halted all construction on the R-Project.

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, 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 public comment period ended on May 9, 2024. Since then, the District continues to engage with the USFWS to finalize the SEIS. Further, the District is participating as a consulting party with the USFWS to work with other stakeholders and Tribal participants to address National Historic Preservation Act Section 106 requirements through the preparation of a new Programmatic Agreement. The District anticipates resuming 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 or 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, 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 2025.

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. In August 2024, the District's motion for summary judgment was sustained by the state district court. The court agreed with the District that no inverse condemnation had occurred and that the property owners sustained no damages from the District. No appeal was filed by the plaintiffs and the matter is closed.

The District 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.

14. SUBSEQUENT EVENTS:

Subsequent significant contracts-
In March 2025, the District entered into a contract for approximately $175.0 million for the labor, supervision, miscellaneous materials, tools and equipment for the fabrication and procurement of 12 Reciprocating Internal Combustion Engines to the plant site, in close proximity to the District-owned Sheldon Station. See additional information in the Planned New Generation Resources section of Management's Discussion and Analysis.

In March 2025, the District entered into a contract for approximately $255.0 million for the procurement and installation of two simple cycle Combustion Turbines as well as key electrical, structural, ductwork, and emission control equipment at the plant site, in close proximity to the District-owned Sheldon Station. See additional information in the Planned New Generation Resources section of the Management's Discussion and Analysis.

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	2024	2023	2022	2021	2020
Service Cost	$ 2,263	$ 2,693	$ 2,663	$ 2,103	$ 2,299
Interest	18,802	18,064	18,237	18,775	19,604
Changes of Benefit Terms	-	-	-	8,598	-
Differences between Expected and Actual Experiences	1,369	(7,325)	(7,054)	(20,995)	(19,961)
Changes of Assumptions	1,825	(8,939)	12,621	9,367	(1,608)
Benefit Payments, net of employee contributions	(17,927)	(16,867)	(15,710)	(14,026)	(12,807)
Net Change in Total OPEB Liability	6,332	(12,374)	10,757	3,822	(12,473)
Total OPEB Liability (Beginning)	307,404	319,778	309,021	305,199	317,672
Total OPEB Liability (Ending) (a)	$ 313,736	$ 307,404	$ 319,778	$ 309,021	$ 305,199
Plan Fiduciary Net Position					
Contributions	$ 2,850	$ 6,294	$ 28,283	$ 28,283	$ 41,084
Net Investment Income (Loss)	47,295	(65,647)	46,479	47,237	41,733
Benefit Payments, net of employee contributions	(17,927)	(16,867)	(15,710)	(14,026)	(12,807)
Administrative Expense	(231)	(212)	(259)	(205)	(188)
Net Change in Plan Fiduciary Net Position	31,987	(76,432)	58,793	61,289	69,822
Plan Fiduciary Net Position (Beginning)	325,910	402,342	343,549	282,260	212,438
Plan Fiduciary Net Position (Ending) (b)	$ 357,897	$ 325,910	$ 402,342	$ 343,549	$ 282,260
Net OPEB (Asset) Liability (Ending) (a) - (b)	$ (44,161)	$ (18,506)	$ (82,564)	$ (34,528)	$ 22,939
Net Position as a % of Total OPEB Liability	114.1%	106.0%	125.8%	111.2%	92.5%
Covered-Employee Payroll	$ 228,081	$ 217,047	$ 200,353	$ 188,451	$ 182,154
Net OPEB (Asset) Liability as a % of Covered-Employee Payroll	(19.4%)	(8.5%)	(41.2%)	(18.3%)	12.6%

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

	2024	2023	2022	2021	2020
Actuarially Determined Contribution	$ 2,050	$ 2,404	$ 2,847	$ 2,871	$ 6,676
Contributions Made in Relation to the Actuarially Determined Contribution	2,406	2,850	6,294	28,283	28,283
Contribution Deficiency (Excess)	$ (356)	$ (446)	$ (3,447)	$ (25,412)	$ (21,607)
Covered-Employee Payroll	$ 250,792	$ 228,081	$ 217,047	$ 200,353	$ 188,451
Contributions as a percentage of covered payroll	1.0%	1.2%	2.9%	14.1%	15.0%

Schedules of Investment Returns for Years Ended December 31,

	2024	2023	2022	2021	2020
Annual Money-Weighted Rate of Return, Net of Investment Expense	12.8%	14.9%	(16.6%)	13.3%	15.6%

Total OPEB Liability	2019	2018	2017	2016
Service Cost	$ 2,771	$ 2,760	$ 3,322	$ 3,229
Interest	19,661	20,032	20,658	19,876
Changes of Benefit Terms	-	-	-	-
Differences between Expected and Actual Experiences	(8,686)	(19,570)	(203)	13,657
Changes of Assumptions	(751)	5,585	(18,807)	(9,149)
Benefit Payments, net of employee contributions	(14,060)	(15,414)	(13,459)	(16,902)
Net Change in Total OPEB Liability	(1,065)	(6,607)	(8,489)	10,711
Total OPEB Liability (Beginning)	318,737	325,344	333,833	323,122
Total OPEB Liability (Ending) (a)	$ 317,672	$ 318,737	$ 325,344	$ 333,833
Plan Fiduciary Net Position				
Contributions	$ 56,706	$ 28,439	$ 74,711	$ 28,242
Net Investment Income (Loss)	(6,892)	21,350	6,102	(453)
Benefit Payments, net of employee contributions	(14,060)	(15,414)	(13,459)	(16,902)
Administrative Expense	(130)	(70)	(69)	(150)
Net Change in Plan Fiduciary Net Position	35,624	34,305	67,285	10,737
Plan Fiduciary Net Position (Beginning)	176,814	142,509	75,224	64,487
Plan Fiduciary Net Position (Ending) (b)	$ 212,438	$ 176,814	$ 142,509	$ 75,224
Net OPEB (Asset) Liability (Ending) (a) - (b)	$ 105,234	$ 141,923	$ 182,835	$ 258,609
Net Position as a % of Total OPEB Liability	66.9%	55.5%	43.8%	22.5%
Covered-Employee Payroll	$ 178,815	$ 171,774	$ 182,197	$ 170,317
Net OPEB (Asset) Liability as a % of Covered-Employee Payroll	58.9%	82.6%	100.4%	151.8%

	2019	2018	2017	2016
Actuarially Determined Contribution	$ 12,967	$ 18,572	$ 21,006	$ 28,283
Contributions Made in Relation to the Actuarially Determined Contribution	41,084	56,706	28,439	74,712
Contribution Deficiency (Excess)	$ (28,117)	$ (38,134)	$ (7,433)	$ (46,429)
Covered-Employee Payroll	$182,154	$178,815	$171,774	$182,197
Contributions as a percentage of covered payroll	22.6%	31.7%	16.6%	41.0%

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

NOTES TO REQUIRED SUPPLEMENTARY INFORMATION (UNAUDITED)

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

Valuation date – Actuarially-determined contribution rates are calculated as of January 1, one year prior to the end of the fiscal year in which contributions are reported. The changes in benefit terms for 2021 were for the addition of the RRA.

Methods and assumptions used to determine contribution rates –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	9-year closed period for 2024 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: 7.6% initial, ultimate 4.5% for 2024 Post-Medicare: 8.5% initial, ultimate 4.5% for 2024 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% for 2024 through 2021
Administrative cost trend	3.0%
Inflation	2.3% for 2024, 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 2024, 2023, and 2020 through 2016 5.75%, net of investment expense, including inflation for 2022 6.0%, net of investment expense, including inflation for 2021
Discount rate	6.25% for 2024 and 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 2024 through 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	80% of males and 50% 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 2024 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 2023 through 2019 80% of males and 30% of females are assumed to have spouses who will elect coverage. Males are assumed to be three years older than their spouses. Females are assumed to be three years younger for 2018 through 2016
Participation rate	95% for 2024 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)	2024	2023
Operating revenues	$ 1,163,637	$ 1,071,924
Operating expenses	(1,155,493)	(1,034,664)
Operating income	8,144	37,260
Investment and other income (loss)	62,224	45,657
Debt and related expenses	(33,553)	(30,792)
Increase in net position	36,815	52,125
Add:		
Debt and related expenses(1)	33,553	30,792
Depreciation and amortization(2)	125,572	128,373
Payments to retail communities(3)	32,164	32,407
Amortization of current portion of financed nuclear fuel(4)	-	3,543
	191,289	195,115
Deduct:		
Investment income retained in construction funds(5)	690	751
Unrealized gain (loss) on investment securities	(1,161)	11,416
	(471)	12,167
Net revenues available for debt service under the General System Bond Resolution	$ 228,575	$ 235,073
General system bonded debt service(6)	100,034	145,163
Ratio of net revenues available for debt service(6)	2.28	1.62

(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's practice is 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 debt service coverage was higher in 2024 than 2023 due primarily to a decrease in General System Bonded Debt Service. The 2023 ratio of net revenues available for debt service (also referred to as debt service coverage) was lower due to 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.

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