

Financial Report 2025



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 31 generating facilities. This diverse power resource mix produces energy from a variety of fuel sources including coal, nuclear, natural gas, oil, hydro, wind and solar. NPPD operates 5,396 miles of transmission and subtransmission lines and 2,366 miles of distribution lines.

Revenues are primarily derived from wholesale power supply agreements with 35 municipalities and 23 public power districts and/or cooperatives.

NPPD also serves an average of more than 95,000 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



31
GENERATING
FACILITIES



530,000+
NEBRASKANS SERVED
TOGETHER WITH OUR
WHOLESALE CUSTOMER
UTILITIES



5,396 MILES
TRANSMISSION &
SUBTRANSMISSION LINES



95,000+
RESIDENTIAL, COMMERCIAL
AND INDUSTRIAL CUSTOMERS



2,366 MILES
DISTRIBUTION
LINES



35
MUNICIPALITIES SERVED
AT WHOLESALE



3,611.9 MW
DIVERSE
GENERATION



81
COMMUNITIES
SERVED BY RETAIL



2,000+
TEAMMATES
WORKING FOR YOU



23
PUBLIC POWER DISTRICTS
SERVED AT WHOLESALE

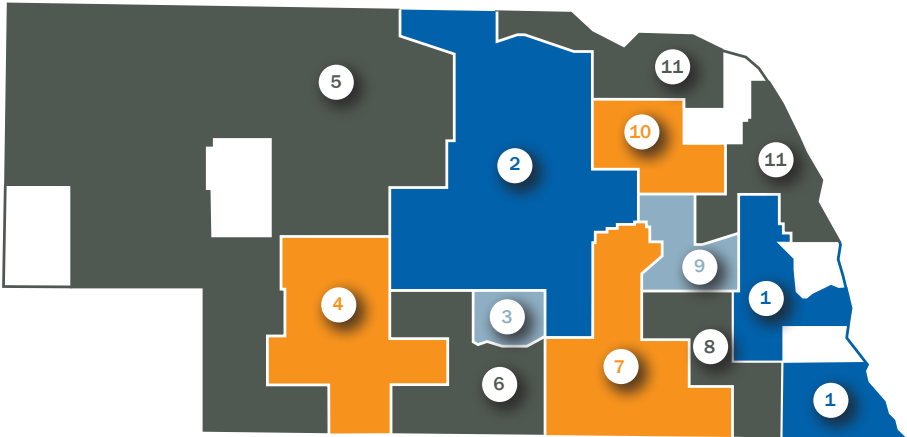


\$1.2 Billion
OPERATING
REVENUE



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
North Platte
Subdivision 4



Rusty M. Kemp
Tryon
Subdivision 5



Rob Hinrichs
Axtell
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

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*



Bill L. Chapin
Vice President,
Energy Production **

* Mr. Wiese was named Vice President, New Construction in January 2026.

** Mr. Chapin was promoted in January 2026 to Vice President, Energy Production.

A Message

FROM OUR 2025 BOARD CHAIR
and CHIEF EXECUTIVE OFFICER



Thomas J. Kent
President & CEO

Jerry L. Chlopek
2025 Board Chair

A handwritten signature in black ink, appearing to read "Tom Kent".

A handwritten signature in black ink, appearing to read "Jerry L. Chlopek".

Each year, a word is chosen that will represent the path ahead. For 2025, it was “collaboration,” and in the end, this was more than a theme. It was the driving force behind every success.

Building Nebraska’s energy future

Collaboration drove one of our biggest milestones: signing a new 35-year Wholesale Power Contract with our wholesale customers. This agreement strengthens a relationship built on trust and positions us to meet energy demand projected to grow by hundreds of megawatts in the next five years. Together, we’re planning responsibly and investing in new generation to support statewide economic development.

To share these plans, we launched emPOWERING Nebraska’s Tomorrow, a program highlighting upcoming projects. These include our new Princeton Road Station, which will add an estimated 694 megawatts (MW) of flexible natural gas generation, and an estimated 717 MW of combustion turbines to be added at our existing Beatrice Power Station. We also completed major transmission projects in Norfolk, Scottsbluff and Kearney and continued work on the R-Project. These are critical infrastructure investments to strengthen reliability, reduce congestion and enable renewable growth.

Managing growth responsibly

Energy demand is truly soaring, with calculations showing we’ve served new demand equal to the

electrical load of 1½ cities the size of Grand Island in the last two years. Since 2023, 30-plus projects have come on-line, with a dozen more underway. Our new load process ensures strategic expansion, avoiding overbuilding while maintaining affordability and capacity. Currently, several projects totaling thousands of megawatts are working through the process.

Keeping energy affordable

Even amid historic growth, affordability remains central. In November, our board approved modest rate adjustments: 3% retail and 1% wholesale, while NPPD continues to rank among the nation’s most affordable utilities. Retail rates remain in the lowest 6.5% nationally; wholesale rates rank in the lowest 12.5%. For the eighth consecutive year, we issued a Production Cost Adjustment credit to wholesale customers – last year to the tune of \$30 million.

Staying true to public power values

When Broken Bow faced a city-wide outage during extreme cold and an unexpected fire at their local power plant in February 2025, our crews quickly deployed a mobile substation to restore power. Across Nebraska, we provided mutual aid to Lincoln Electric System, Omaha Public Power District, and the city of Seward after severe storms. Beyond state lines, NPPD crews assisted Georgia and Florida following Hurricanes Helene and Milton, earning a national commendation from the American Public Power Association for

exemplifying the spirit of public power: neighbors helping neighbors.

Celebrating milestones

2025 also marked major anniversaries: Beatrice Power Station turned 20, Ainsworth Wind Energy Facility celebrated 20 years, and our Customer Care Contact Center reached 25 years of service. Each milestone is a testament to decades of reliability and customer care.

Driving innovation

Innovation continued to propel us forward. NPPD earned first place at The Energy Authority's Hackathon for an AI-powered vegetation management solution that could set new industry standards. We also strengthened cybersecurity through advanced training and partnerships, including participation in Cyber Tatanka and GridEx exercises, global and national exercises, respectively, simulating coordinated attacks on the electric grid and critical infrastructure. These important drills ensure our readiness against evolving threats.

Leading in nuclear energy

In January 2025, Gov. Jim Pillen publicly recognized nuclear's vital role in Nebraska's economy. Cooper Nuclear Station remains a cornerstone of carbon-free generation, and we are pursuing a license extension through 2054 and considering a power uprate of approximately 10%. Through the newly formed Great Plains New Nuclear Consortium, we're exploring next-generation technologies like Small Modular Reactors. In addition, we continue evaluating sites for up to 2,000 MW of new nuclear capacity in-state. These efforts are supported by clean energy tax credits and legislative funding.

Earning awards of excellence

Safety is at the heart of our culture. In 2025, NPPD earned the National Safety Council's Safest Company Award with Distinction and the APPA Diamond Safety Award of Excellence, along with honors for wellness, communications, transmission and distribution, engineering and economic development. These achievements reflect our commitment to excellence in every area of our business.

Engaging with customer communities

Public power means more than electricity. It means improving lives. In 2025, we connected with communities through the Nebraska State Fair, an Arbor Day celebration in Tekamah, and the Nebraska Open, which raised more than \$75,000 in community college scholarships. Our Pennies for Power program reached \$1 million in contributions since inception, helping local families. We also hosted community assistance fairs to provide financial resources and support for local families.

Looking ahead

As Nebraska's economy grows, NPPD is launching its largest generation and transmission expansion since the 1970s and investing billions over the next several years to ensure reliable, affordable power for decades to come. Leadership changes announced in December 2025 will keep these priorities front and center, aligning our structure with the future we envision.

Our word for 2026 is "momentum" because the foundation built in 2025 is driving us forward. Together with our customers, communities and partners, we're building a resilient, sustainable energy future for Nebraska.

2025

FINANCIAL REPORT

NEBRASKA PUBLIC POWER DISTRICT

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YEAR AT A GLANCE

KILOWATT - HOUR SALES	18.4 BILLION
OPERATING REVENUES	\$ 1,154.6 MILLION
COST OF POWER PURCHASED AND GENERATED	\$ 651.6 MILLION
OTHER OPERATING EXPENSES	\$ 473.6 MILLION
INVESTMENT AND OTHER INCOME	\$ 64.2 MILLION
DEBT AND RELATED EXPENSES	\$ 33.8 MILLION
INCREASE IN NET POSITION	\$ 59.8 MILLION
DEBT SERVICE COVERAGE	2.60 TIMES

2025 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		Revenues (in 000's)	
				Amount	%	Amount	%
Retail:							
Residential	10.93 ¢	13.05 ¢	75,267	865,571	4.7	\$ 112,990	9.8
Commercial	8.58 ¢	10.11 ¢	20,118	1,088,477	5.9	110,064	9.5
Industrial	4.45 ¢	4.91 ¢	62	2,156,696	11.7	105,973	9.2
Total Retail Sales	6.91 ¢	8.00 ¢	95,447	4,110,744	22.3	329,027	28.5
Wholesale:							
Municipalities ⁽²⁾		5.90 ¢	35	1,363,862	7.4	80,452	7.0
Public Power Districts and Cooperatives ⁽²⁾		5.39 ¢	23	8,749,130	47.5	471,412	40.8
Total Firm Wholesale Sales		5.46 ¢	58	10,112,992	54.9	551,864	47.8
Total Firm Retail and Wholesale Sales		6.19 ¢	95,505	14,223,736	77.2	880,891	76.3
Participation and Capacity Sales		5.16 ¢	5	1,021,177	5.5	52,681	4.6
Other Sales ⁽³⁾		4.94 ¢	1	3,177,194	17.3	157,019	13.6
Total Electric Energy Sales		5.92 ¢	95,511	18,422,107	100.0	1,090,591	94.5
Other Operating Revenues ⁽⁴⁾						67,740	5.8
Unearned Revenues ⁽⁵⁾						(3,776)	(0.3)
Total Operating Revenues						\$ 1,154,555	100.0

COST OF POWER PURCHASED AND GENERATED	MWh		Costs (in 000's)	
	Amount	%	Amount	%
Production ⁽⁶⁾	15,051,004	78.5	\$ 468,037	71.8
Power Purchased	4,132,395	21.5	183,610	28.2
Total Production and Power Purchased	19,183,399	100.0	\$ 651,647	100.0

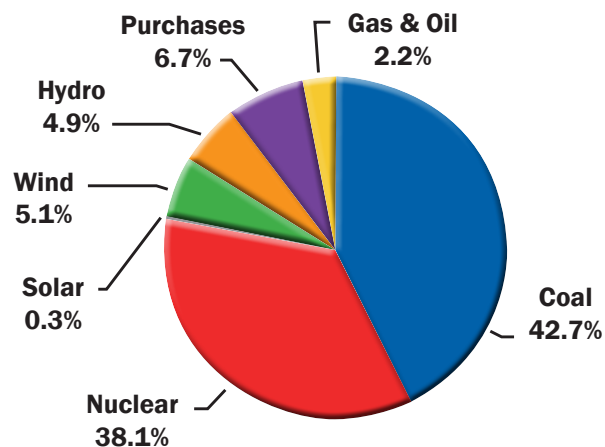
CONTRACTUAL AND TAX PAYMENTS (in 000's) ⁽¹⁾	Amount
Payments to Retail Communities	\$ 34,223
Payments in Lieu of Taxes	10,959
Total Contractual and Tax Payments	\$ 45,182

OTHER	Amount
Miles of Transmission and Subtransmission Lines in Service	5,396
Number of Full-Time Employees	2,047

- (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 (“MD&A”) (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, 2025 and 2024. The Statements of Revenues, Expenses, and Changes in Net Position present the operating results for the years 2025 and 2024. The Statements of Cash Flows present the sources and uses of cash and cash equivalents for the years 2025 and 2024. The Statements of Fiduciary Net Position present the financial resources available for other postemployment benefits (“OPEB”) as of December 31, 2025 and 2024. The Statements of Changes in Fiduciary Net Position present the additions, deductions and changes in net position restricted for OPEB as of December 31, 2025 and 2024. 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, 2025 and 2024, and the results of operations for the years 2025 and 2024. The Required Supplementary Information includes 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 2,047 full-time employees as of December 31, 2025. The District has the authority, 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 Constitution 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 (“SPP IM”). Under the SPP IM, all energy produced by the District’s generating resources is sold to the SPP IM, and all energy required to serve firm requirements customers is purchased from the SPP IM. 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 in the SPP IM in 2025 and 2024.

As a Load Responsible Entity (“LRE”) in SPP, the District is required to maintain sufficient accredited capacity to meet its forecasted peak demand plus the Planning Reserve Margin (“PRM”) for both the Summer and Winter resource adequacy seasons. The District’s highest summer peak load of 3,087.8 MW was established in August 2023 and its highest winter peak load of 2,503.1 MW was established in February 2025 for firm requirements customers.

To meet the peak load in 2025 of 2,989.5 MW, the District had available 3,846.1 MW of capacity resources that included 3,025.5 MW of generation capacity from 11 owned and operated generating plants and 20 plants over which the District has operating control, 443.9 MW of firm capacity purchases from the Western Area Power Administration (“Western”), 162.7 MW of a capacity purchase from Omaha Public Power District’s (“OPPD”) Nebraska City Station Unit No. 2 (“NC2”) coal-fired plant, 106 MW of a capacity purchase and an associated energy call-option and 68 MW of a renewable capacity purchase with Associated Electric Cooperative, Inc. (“AECI”) during the period of June 1, 2025, through September 30, 2025, and 40 MW of a capacity purchase from Nextera Energy Marketing, LLC, during the period of June 1, 2025 through May 31, 2029. Of the total capacity resources of 3,846.1 MW, 234.2 MW are being sold via participation sales or other capacity sales agreements, leaving 3,611.9 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 2025 accredited capacity.

Type	CAPACITY RESOURCES		
	Number of Plants ⁽¹⁾	Summer 2025 Accredited Capacity (MW) ⁽²⁾	Percent of Total
Steam - Conventional ⁽³⁾	3	1,678.3	55.5
Steam - Nuclear	1	768.5	25.4
Hydro	5	104.0	3.4
Diesel	10	68.9	2.3
Combustion Turbine ⁽⁴⁾	3	123.0	4.0
Combined Cycle	1	219.5	7.3
Wind ⁽⁵⁾	8	63.3	2.1
	<u>31</u>	<u>3,025.5</u>	<u>100.0</u>

- (1) Includes three hydro plants and ten diesel plants under contract to the District.
- (2) Accreditation by SPP for the summer season 2025, 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 have identified a need for additional generating capacity. 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.

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 2021 through 2025.

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

Year	Coal ⁽¹⁾	Nuclear	Hydro ⁽²⁾	Wind ⁽³⁾	Gas and Oil	Purchases ⁽⁴⁾	Solar ⁽⁵⁾
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
2025	42.7	38.1	4.9	5.1	2.2	6.7	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 IM 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 2025 accredited capacity and in-service dates.

DISTRICT-OWNED GENERATION FACILITIES

Facility	Fuel Type	Summer 2025 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	214.0	1961, 1968
Combustion Turbines (3 generating plants)	Oil or Natural Gas	123.0	1973
Canaday Station	Natural Gas	99.3	1958
Hydro (2 generating plants)	Water	24.0	1888, 1937
Ainsworth Wind Energy Facility ⁽²⁾	Wind	4.9	2005
		2,818.2	

- (1) 2025 summer accredited net capacity based on SPP criteria.
- (2) Nominally rated at 60 MW.

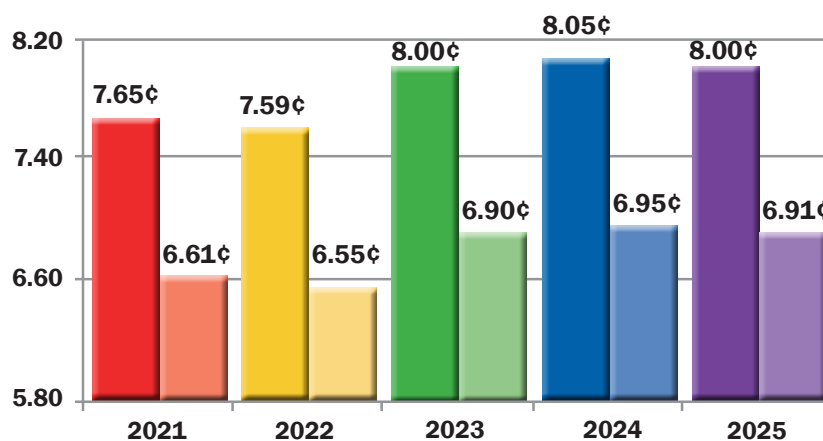
THE CUSTOMERS

Retail and Wholesale Customers

In 2025, the District served an average of 95,447 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. 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, 2021, through 2025. 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 decrease in the average cents per kWh sold in 2025 from 2024 was due primarily to a 13.1% increase in industrial energy sales in 2025 as industrial energy sales have the lowest rate of all the retail customer classes. 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.

AVERAGE CENTS PER kWh SOLD - RETAIL
(Retail - All Classes)



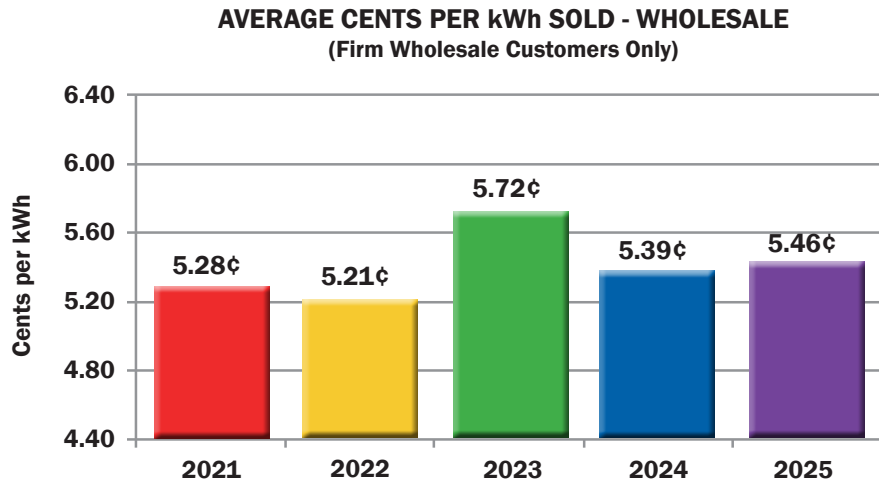
Average Cents per kWh Sold Average Cents per kWh Sold Less Government Taxes/Transfers

Wholesale Power Contracts (“2016 Contracts”) with wholesale customers require them to purchase total demand and energy requirements from the District, subject to certain exceptions. The 2025 wholesale revenues were made up of wholesale customers being served under the 2016 Contracts which included 22 public power districts, one cooperative and 35 municipalities. Nineteen of the public power districts and the one cooperative are served under one contract with the Nebraska Generation and Transmission Cooperative. Any wholesale customer that did not execute a 2026 Contract on or before October 31, 2025 will continue with the 2016 Contract which includes the provision relating to a wholesale customer’s right to reduce its purchases from the District if a certain performance standard regarding wholesale power costs is not met. 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. 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 District has entered into new Wholesale Power Contracts (“2026 Contracts”), that replace the 2016 Contracts, with a substantial majority of its wholesale customers. The 2026 Contracts became effective on January 1, 2026, and terminate on December 31, 2060. The 2026 Contracts provide for the District to sell and such wholesale customers to purchase their total demand and energy requirements, subject to certain exceptions, from the District. The 2026 Contracts include provisions relating to a wholesale customer’s right to terminate its 2026 Contract on or after January 1, 2036, or to cap its purchases from the District under its 2026 Contract on or after January 1, 2036.

As of December 31, 2025, four Nebraska wholesale customers, representing 9.4% of the District’s 2025 total operating revenues, have not yet executed the 2026 Contracts, but the District continues to have discussions with these customers regarding the 2026 Contracts. If said wholesale customers do not enter into the 2026 Contracts, said wholesale customers will continue to purchase their total demand and energy requirements from the District pursuant to the 2016 Contracts.

The following chart shows the District’s average wholesale cents per kWh for the years ended December 31, 2021, through 2025. The increase in average cents per kWh sold in 2025 over 2024 was due primarily to a \$9.5 million reduction in the actual PCA refunds, partially offset by an increase in kWh sales. 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 ended on September 30, 2025.

Transmission Customers

The District owns and operates 5,396 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, 2023 through 2025.

Calendar Year	Average Number of Retail Customers	Wholesale Customers ⁽¹⁾	Megawatt-Hour Sales				Peak Load (MW)
			Native Load Sales ⁽²⁾	Percentage Growth ⁽⁴⁾	Total Sales ⁽³⁾	Percentage Growth ⁽⁴⁾	Busbar Native Load
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
2025	95,447	64	14,223,736	4.1	18,422,107	3.8	2,989.5

- (1) Wholesale customers include sales to firm wholesale customers, participation customers (Lincoln, MEAN, OPPD and Grand Island), capacity customers and nonfirm customers. The decrease by one in 2025 from 2024 and in 2024 from 2023 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 2025 over 2024 was due primarily to a 3.0% increase in wholesale energy sales. The increase in native load sales in 2024 over 2023 was due primarily to a 4.5% increase in wholesale energy sales.
- (3) Total sales from the System include sales to Lincoln from Gerald Gentleman Station; to MEAN, OPPD and Grand Island from Ainsworth Wind Energy Facility, which sales commenced October 1, 2005, and terminated 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 footnote (2) for explanations for the change in native load sales. The increase in percentage growth for total sales in 2025 over 2024 was due primarily to an increase in nonfirm energy sales from the Cooper Nuclear Station as it was a non-outage year. The decrease in percentage growth for total sales 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.

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,	2025	2024	2023
Current Assets	\$ 1,335,685	\$ 1,033,846	\$ 1,052,977
Special Purpose Funds	791,770	751,829	745,582
Utility Plant, Net	2,943,279	2,637,854	2,551,805
Other Long-Term Assets	210,408	225,079	189,999
Total Assets	5,281,142	4,648,608	4,540,363
Deferred Outflows of Resources	244,528	277,784	284,067
Total Assets and Deferred Outflows	<u>\$ 5,525,670</u>	<u>\$ 4,926,392</u>	<u>\$ 4,824,430</u>
Current Liabilities	\$ 283,085	\$ 505,902	\$ 304,588
Long-Term Debt	1,289,766	831,507	959,809
Other Long-Term Liabilities	982,459	909,968	878,951
Total Liabilities	2,555,310	2,247,377	2,143,348
Deferred Inflows of Resources:			
Unearned Revenues	202,125	224,349	258,311
Other Deferred Inflows	651,254	397,485	402,405
Net Position	2,116,981	2,057,181	2,020,366
Total Liabilities, Deferred Inflows, and Net Position	<u>\$ 5,525,670</u>	<u>\$ 4,926,392</u>	<u>\$ 4,824,430</u>

Total Assets and Deferred Outflows

Total Assets as of December 31, 2025, increased \$632.5 million or 13.6% over total assets as of December 31, 2024, due primarily to higher balances for investments, receivables, materials and supplies, decommissioning funds, utility plant in service, and construction work in process. Investments were higher due primarily to the receipt of the 45U credit received in 2025 for the filing of the 2024 return and due to funds pre-collected for Cooper Nuclear Station's 2026 outage, revenue-funded capital projects, and construction deposits. Receivables were higher due primarily to the accrual of the 2025 tax filing for the 45U credit. 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. Decommissioning funds for Cooper Nuclear Station were higher due to favorable market conditions in 2025. Utility plant in service was higher due to new assets being completed and placed into service in 2025. Construction work in progress was significantly higher due to increased capital expenditures to meet higher customer loads. These increases in Total Assets were partially offset by a reduction in fossil fuels inventories, nuclear fuel, and other long-term assets.

Deferred Outflows as of December 31, 2025, decreased \$33.3 million or 12.0% from deferred outflows as of December 31, 2024, due primarily to the favorable market conditions which decreased the regulatory asset associated with asset retirement obligations ("ARO") and due to the amortization of OPEB deferred outflows in 2025.

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 Liabilities, Deferred Inflows and Net Position

Total Liabilities as of December 31, 2025, increased \$307.9 million or 13.7% over total liabilities as of December 31, 2024, due primarily to higher balances for revolving credit agreements, accounts payable and accrued liabilities, asset retirement obligations, and other current liabilities. Revolving credit agreements were higher due to increased amounts outstanding for capital projects. 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. 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, 2025, increased \$231.5 million or 37.2% from deferred inflows as of December 31, 2024, due primarily to increases in regulatory liabilities, including the authorization of the 45U credit regulatory liability recorded in 2025 and including the pre-collection for Cooper Nuclear Station outage costs that will occur in 2026. The increase in Deferred Inflows was partially offset by a net reduction in rate stabilization fund balances or unearned revenues.

Net Position as of December 31, 2025, increased \$59.8 million over December 31, 2024. The reasons for this change are disclosed in the analysis section for the Statements of Revenues, Expenses, and Changes in 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.

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

For the years ended December 31,	2025	2024	2023
Operating Revenues	\$ 1,154,555	\$ 1,163,637	\$ 1,071,924
Operating Expenses	(1,125,179)	(1,155,493)	(1,034,664)
Operating Income	29,376	8,144	37,260
Investment and Other Income	64,221	62,224	45,657
Debt and Related Expenses	(33,797)	(33,553)	(30,792)
Change in Net Position	\$ 59,800	\$ 36,815	\$ 52,125

SOURCES OF OPERATING REVENUES (in 000's)

For the years ended December 31,	2025	2024	2023
Firm Retail and Wholesale Sales	\$ 880,891	\$ 839,158	\$ 842,737
Participation and Capacity Sales	52,681	53,914	67,399
Other Sales	157,019	147,365	178,701
Other Operating Revenues	67,740	63,688	68,537
Unearned Revenues	(3,776)	59,512	(85,450)
Total Operating Revenues	\$ 1,154,555	\$ 1,163,637	\$ 1,071,924

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. Transmission costs not recovered from the District's wholesale power contracts are expected to be recovered through rates charged by SPP. The rates for retail service include an amount to recover the costs of wholesale power service in addition to distribution system costs for the then current year. The District had no overall wholesale base rate changes in 2025 and 2024. In 2026, the overall wholesale base rate will increase 1.0%. In 2025 the District had an increase of 2.0% in the overall average retail base rate and no change in the overall average retail base rate in 2024. Retail will have a 3.0% increase in the overall average base rates in 2026.

The 2016 Contracts and 2026 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 and 2026 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 and Customer Committee that are established pursuant to the 2016 Contracts and 2026 Contracts, respectively. 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 \$30.8 million, \$53.0 million, \$56.8 million, and \$33.9 million, for 12-month periods beginning January 1, 2026, January 1, 2025, January 1, 2024, and February 1, 2023, respectively. The PCA equated to a one-year average bill reduction for wholesale customers compared to base rates of 3.5%, 6.1%, 7.2%, and 4.4%, respectively. The PCA also resulted in an average annual decrease for retail customers of 0.7%, 1.0%, 1.0%, and 2.2%, compared to base rates for the respective 12-month periods. Details of the District's Retail and Wholesale Power Contracts are included in Note 12.C., *Retail Agreements and Wholesale Power Contracts*, in the Notes to Financial Statements.

Revenues from firm sales increased \$41.7 million, or 5.0%, from \$839.2 million in 2024 to \$880.9 million in 2025. The increase was due primarily to a lower PCA rate for refunds in 2025 and increases in retail and wholesale energy sales. 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 Participation and Capacity Sales

Revenues from participation and capacity sales decreased from \$53.9 million in 2024 to \$52.7 million in 2025, a decrease of \$1.2 million, or 2.2%. The decrease was due primarily to reduced revenues for capacity sales, including a capacity sales agreement with OPPD which expired on May 31, 2025. Revenues from participation and capacity 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 Other Sales

Revenues from other sales consist of sales in the SPP IM and nonfirm sales to other utilities. TEA has energy marketing responsibilities for the District's other and nonfirm off-system sales and the related management of credit risks. Other sales include non-energy transactions, such as auction revenue rights ("ARR") and transmission congestion rights ("TCR") which do not have kWh associated, which therein skews the average cents per kWh sold. Other sales increased from \$147.4 million in 2024 to \$157.0 million in 2025, an increase of \$9.6 million, or 6.5%. The increase was due primarily to increased non-energy transactions (ARR and TCR) in 2025. 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 Operating Revenues

Other operating revenues consist primarily of revenues from transmission and other miscellaneous revenues. These revenues were \$67.7 million, \$63.7 million, and \$68.5 million in 2025, 2024, and 2023, respectively. The majority of these revenues consist of those received from other SPP transmission customers. Other operating revenues increased from \$63.7 million in 2024 to \$67.7 million in 2025, an increase of \$4.0 million, or 6.3%. The increase was due primarily to SPP revenues received from other transmission customers. Other operating revenues decreased from \$68.5 million in 2023 to \$63.7 million in 2024, a decrease of \$4.8 million, or 7.0%. The decrease 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 AECl, which was in effect during 2023 only, for the use of District-owned transmission.

Unearned Revenues

Under the provisions of the 2016 Contracts and 2026 Contracts, any surplus or deficit between net revenues and revenue requirements, within certain limits set forth in the 2016 and 2026 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 2025, 2024, and 2023, respectively (in 000’s).

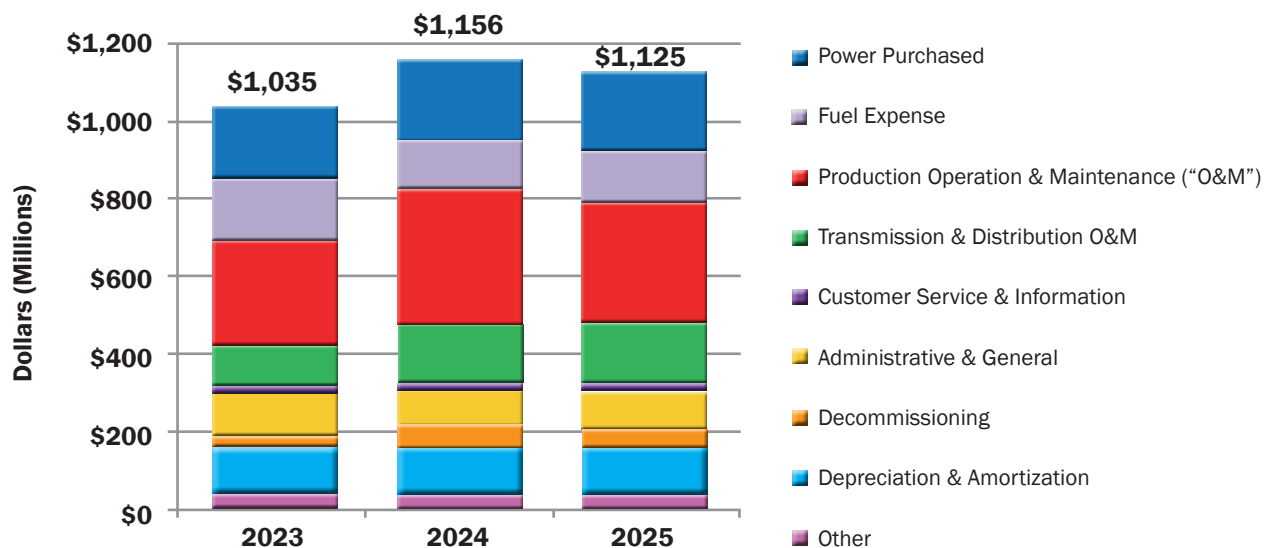
	2025	2024	2023
Surplus revenues deferred to future periods	\$ (39,646)	\$ (33,793)	\$ (67,007)
Refunded revenues from prior periods	61,870	67,755	76,453
CNS outage collections	(26,000)	25,550	(25,550)
CNS reserve	-	-	(69,346)
	<u>\$ (3,776)</u>	<u>\$ 59,512</u>	<u>\$ (85,450)</u>

The following table shows the balance of the regulatory liability for unearned revenues to be applied as credits against revenue requirements in future rate periods was \$202.1 million, \$224.3 million, and \$258.3 million, as of December 31, 2025, 2024, and 2023, respectively (in 000’s).

	2025	2024	2023
Unearned revenues, beginning of year	\$ 224,349	\$ 258,311	\$ 267,758
Surpluses	39,646	33,793	\$ 67,006
Use of prior period rate stabilization funds in rates	(61,870)	(67,755)	\$ (76,453)
Unearned revenues, end of year	<u>\$ 202,125</u>	<u>\$ 224,349</u>	<u>\$ 258,311</u>

Operating Expenses

The following chart illustrates operating expenses for the years ended December 31, 2023, through 2025.



Total operating expenses in 2025 were \$1,125.2 million, a decrease of \$30.3 million from 2024. Total operating expenses in 2024 were \$1,155.5 million, an increase of \$120.8 million over 2023. The changes were due primarily to the following:

Power purchased expenses were \$183.6 million, \$189.8 million, and \$179.2 million in 2025, 2024, and 2023, respectively. These expenses decreased \$6.2 million in 2025 from 2024 due primarily to lower costs in 2025 from the SPP IM, NC2, Kingsley, and solar purchases, which were partially offset by higher costs for wind agreements, special power products, Western, Loup, and capacity town purchases. These expenses increased \$10.6 million in 2024 over 2023 due primarily to increased quantities and purchases in SPP IM, 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.

Fuel expenses were \$156.9 million, \$145.0 million, and \$161.5 million in 2025, 2024, and 2023, respectively. These expenses increased \$11.9 million in 2025 over 2024 due primarily to higher costs for Cooper Nuclear Station, Gerald Gentleman Station, Beatrice Power Station, Sheldon Station, and Canaday Station, which were partially offset by lower costs for oil for the CT units. The higher costs for the Cooper Nuclear Station, Gerald Gentleman Station, Beatrice Power Station, Sheldon Station, and Canaday Station, in 2025 were due primarily to higher generation at these facilities in 2025 over 2024. The lower costs for the CT units was due to lower generation. Fuel 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.

Production operation and maintenance expenses were \$311.1 million, \$350.7, million, and \$275.4 million in 2025, 2024, and 2023, respectively. These expenses decreased \$39.6 million in 2025 from 2024 due primarily to the planned refueling and maintenance outage at Cooper Nuclear Station in 2024. 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.

Transmission and distribution operation and maintenance expenses were \$135.2 million, \$128.8 million, and \$119.8 million in 2025, 2024, and 2023, respectively. These costs increased \$6.4 million in 2025 over 2024 due primarily to increased costs for SPP fees, contractor labor, and salaries and benefits. 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.

Customer service and information expenses were \$23.4 million, \$22.5 million, and \$18.6 million in 2025, 2024, and 2023, respectively. These expenses increased \$0.9 million in 2025 over 2024 due primarily to an increase in interest expense on customer deposits. 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 \$107.4 million, \$103.7 million, and \$91.1 million in 2025, 2024, and 2023, respectively. These expenses increased \$3.7 million in 2025 over 2024 due primarily to an increase in overall salaries and benefits and outside services for Princeton Road Station. 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.

Payments to retail communities were \$34.2 million, \$32.2 million, and \$32.4 million in 2025, 2024, and 2023, respectively. These payments were collected from retail customers in communities with PRO Agreements and remitted to the communities. These payments increased \$2.0 million in 2025 over 2024 due primarily to higher retail revenues and an increase in the percentage of revenues collected for certain communities.

Decommissioning expenses were \$40.1 million, \$46.9 million, and \$18.1 million in 2025, 2024, and 2023, 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. See Note 9. *Asset Retirement Obligations ("ARO")*, in the Notes to Financial Statements for details about the District's regulatory accounting methodology for AROs. Decommissioning expenses for non-nuclear assets and Cooper Nuclear Station were \$15.8 million and \$24.3 million, respectively, in 2025. Decommissioning expenses decreased in 2025 from 2024 due primarily to a reduction in the amount of collections in rates for decommissioning costs of Cooper Nuclear Station. 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.

Depreciation and amortization expenses were \$122.2 million, \$125.6 million, and \$128.4 million in 2025, 2024, and 2023, respectively.

Payments in lieu of taxes were \$11.0 million, \$10.4 million, and \$10.2 million in 2025, 2024, and 2023, 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 were \$64.2 million, \$62.2 million, and \$45.7 million in 2025, 2024, and 2023, respectively. The increase of \$2.0 million in 2025 over 2024 and the increase of \$16.5 million in 2024 over 2023, were due primarily to favorable market returns in 2025 and 2024, respectively.

Debt and Related Expenses

Debt and related expenses were \$33.8 million, \$33.6 million, and \$30.8 million in 2025, 2024, and 2023, respectively. The increase of \$0.2 million in 2025 over 2024 was due primarily to a decrease in bond premium amortization and higher interest expense on revolving credit agreements because of higher interest rates, which was partially offset by lower interest expense on revenue bonds and an increase in interest during construction of capital assets. The increase of \$2.8 million in 2024 over 2023 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 \$59.8 million, \$36.8 million, and \$52.1 million in 2025, 2024, and 2023, respectively. The change in net position in 2025 increased \$23.0 million over 2024 due primarily to investment gains due to strong market conditions, higher rate collections for principal payments for debt service and construction from revenue, which were partially offset by increased expense related to capitalized interest. 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.

CONDENSED STATEMENTS OF CASH FLOWS (in 000's)

For the years ended December 31,	2025	2024	2023
Net Cash Provided by Operating Activities	\$ 265,556	\$ 143,281	\$ 289,851
Net Cash Provided by Noncapital Financing Activities	95,438	-	-
Net Cash Provided by (Used in) Investing Activities	(147,977)	49,993	(80,580)
Net Cash Used in Capital and Financing Activities	(213,279)	(203,706)	(214,399)
Net Increase (Decrease) in Cash and Cash Equivalents	(262)	(10,432)	(5,128)
Cash and Cash Equivalents, Beginning of Year	3,569	14,001	19,129
Cash and Cash Equivalents, End of Year	\$ 3,307	\$ 3,569	\$ 14,001

The increase in net cash provided by operating activities in 2025 over 2024 was due to higher receipts from customers. The increase in net cash provided by noncapital financing activities was due to the receipt of the 45U credit received in 2025 for the filing of the 2024 return. The decrease in net cash provided by investing activities was due to a net purchase position in 2025 compared to a net sell/maturity position in 2024. The increase in net cash used in capital and financing activities in 2025 over 2024 was primarily due to higher principal and interest payments on revolving credit agreements and notes, along with higher capital expenditures for utility plant. 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.

FINANCIAL MANAGEMENT POLICY

The District has a Financial Management Policy (the "Policy") that has been approved by the Board and is subject to periodic review and revisions. 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 for all years 2025 and prior. In 2026 the District has established a range for targeted debt service coverage of 1.5 to 2.0 times. Debt service coverage ratios were 2.60, 2.28, and 1.62 in 2025, 2024, and 2023, respectively. The debt service coverage was higher in 2025 than 2024 due primarily to an increase in net revenues available for debt service (also referred to as debt service coverage). The 2025 ratio of net revenues available for debt service was higher due to lower operating expenses and the amortization of the current portion of financed nuclear fuel. The debt service coverage increase in 2024 over 2023 was due primarily to a decrease in General System Bonded Debt Service. 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. For additional details, 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 as of December 31, 2025:

Fitch Ratings	A+	(stable outlook)
Moody's Investors Service	A1	(stable outlook)
S&P Global Ratings	A	(stable outlook)

The District plans, pursuant to the Policy, to issue separate series of indebtedness, including separate series of General Revenue Bonds, for production, transmission, and retail projects. No more than 20.0% of the amount of outstanding indebtedness issued for production projects, calculated at the time of issuance of each series of such indebtedness, or \$200.0 million, whichever is less, will be permitted to mature after the end of the longest term of any wholesale power contract in place with customers. As of January 1, 2026, the end of the longest term of any wholesale power contract is 2060, which is the end of the 2026 Contracts. Transmission indebtedness issued for transmission projects is expected to mature over the useful life of the asset that is being financed. For ratemaking purposes, transmission indebtedness is allocated to wholesale and retail customers who use the District's transmission facilities, and to revenue requirements recovered from others through the SPP tariffs. The outstanding indebtedness limit in the Policy does not apply to transmission indebtedness.

The District will issue additional debt in 2026 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, commercial paper, 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 \$2,629.7 million, \$862.9 million, and \$105.8 million in 2025, 2024, and 2023, 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 and debt proceeds.

Significant capital projects for 2025 included:

- \$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 Notification to Construct ("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

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 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:

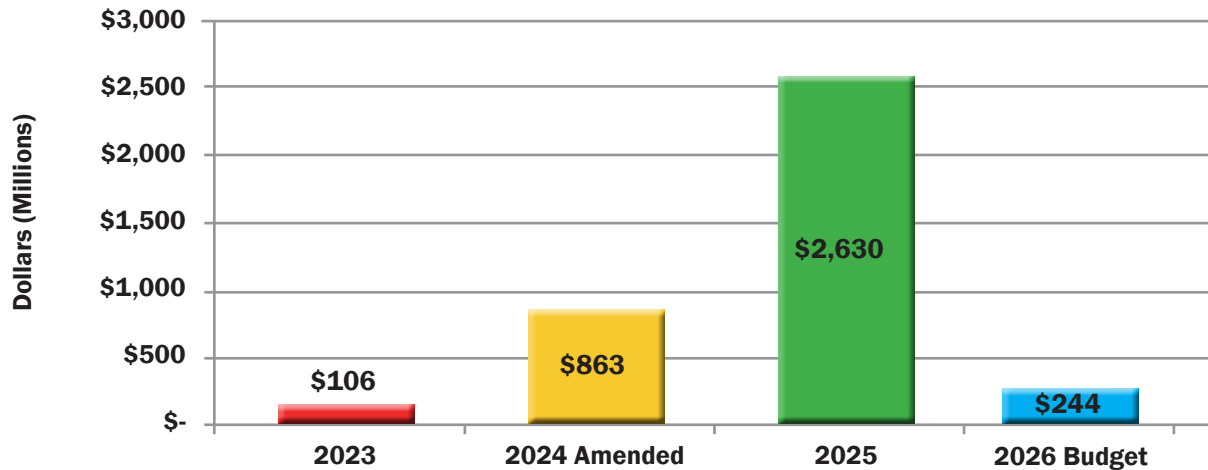
- \$9.3 million for Columbus East 115 kV transformer upgrade
- \$8.9 million for Gerald Gentleman Station Unit 2 boiler tube surface replacement
- \$5.6 million for Sheldon Station condenser and dewatering bins replacement/upgrade
- \$5.5 million for Cooper Nuclear Station 316(b) environmental modifications
- \$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

Other authorized capital projects for renewals and replacements to existing facilities and other additions and improvements totaled \$149.3 million, \$132.2 million, and \$54.9 million for 2025, 2024, and 2023, respectively.

The Board-approved budget for capital projects for 2026 is \$244.4 million. Some of the specific capital projects for 2026 include:

- \$83.2 million for 2026 supplement to 345kV R-Project line, an SPP NTC Project
- \$22.3 million for Gerald Gentleman Station High Pressure Turbine Replacement
- \$11.4 million for Tobias 345kV substation upgrade Elm Creek to Tobias 345kV line
- \$10.0 million for Production & Transmission corporate unspecified blanket
- \$5.3 million for Holt 345kV substation upgrade Antelope to Holt County 345kV line
- \$4.5 million for Stanton North-Hoskins 15kV line
- \$4.4 million for Cooper Nuclear Station simulator upgrade

The following chart illustrates the Board-approved capital projects for the years ended December 31, 2023, through 2025, including the Board-approved budget for the year ended December 31, 2026.



PRINCETON ROAD STATION

In order to address load growth and increases in the Resource Adequacy Requirements (“RAR”), which are being adopted by SPP to ensure that there is sufficient capacity and reliability during periods of peak demand, the District has initiated the process necessary to begin the construction of a new generation facility (the “Princeton Road Station”) north of Hallam, Nebraska. The Princeton Road Station is located on the northwest corner of South 42nd Street and Princeton Road in Lancaster County, Nebraska. This facility will support the use of twelve Wartsila 18.1 MW RICE generators and two Siemens CT generators rated at 239 MW each, with a total rated capacity for the site being nearly 700 MW. The Princeton Road Station will be capable of operating on fuel oil or natural gas as fuel sources for the RICE and CTs. Major procurements have been executed including contracts with Wartsila and Siemens, with delivery expected in Spring 2027 and Spring 2028, respectively. The District also procured the Generator Step-up and Auxiliary transformers, with delivery expected in Spring 2028. An Engineer Procure and Construct (“EPC”) contract is in place with Burns and McDonnell that includes all the work/procurement of equipment needed to build and commission the Princeton Road Station generation facility.

The District has contracted with Northern Natural Gas Company to provide firm natural gas pipeline services and construct necessary facilities including mainline upgrades, branch pipeline addition, and a new town border station to deliver natural gas to Princeton Road Station.

The Princeton Road Station facility was studied in the SPP 2023 generator interconnection process and will connect to the nearby existing 345 kV and 115 kV transmission system with no additional network upgrades required. Construction of the interconnection facilities are not part of the EPC contract with Burns and McDonnell and will be covered by separate future contracts. Air modeling for the site has been submitted to the Lincoln Lancaster County Department of Health and the Air Quality Permit is expected to be approved mid-year 2026, after which the construction of the facility may commence. The Princeton Road Station facility was approved by the Nebraska Power Review Board (“NPRB”) in September 2025. Site grading began in March 2026, and commercial operation of the Princeton Road Station is targeted for June 1, 2029. The current estimated cost for the Princeton Road Station and the associated transmission projects is \$2.3 billion. Final costs for the Princeton Road Station could be higher than the estimate due to numerous cost variables which have not been finalized.

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 new substation adjacent to an existing substation east of Thedford, then eastward to an existing substation in Holt County that is 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 generation in an area of the state that lacks transmission access. The expected cost of the R-Project is \$816.5 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*.

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 included 89 transmission upgrades, over 2,000 miles of new transmission lines and nearly 500 miles of transmission rebuilds which approximates \$7.7 billion in projects in the SPP region. The District’s share of this investment is estimated to be \$385 million, which will be recognized as O&M expense over the life of the transmission assets once the assets are placed into service and will be recovered through the District’s transmission rates. Of these 89 projects from the 2024 SPP ITP, five have been identified as NTCs for the District with an estimated total investment of \$313.5 million. The District is responsible for constructing and funding these NTCs however, \$253.6 million of the \$313.5 million will be recovered from SPP members and the remaining costs will be recovered through the District’s transmission rate.

In November 2025, the SPP Board of Directors approved the 2025 ITP. The 2025 ITP includes 50 transmission upgrades across the SPP footprint, over 1,000 miles of new transmission lines representing approximately \$8.6 billion in projects in the SPP region. The District’s share of this investment is approximately \$430 million, which will be recognized as O&M expense over the life of the transmission assets once the assets are placed into service and will be recovered through the District’s transmission rates. Of these 50 projects, two have been identified as NTCs for the District, with an estimated total cost of \$45.5 million. The District is responsible for constructing and funding these NTCs however, \$34.4 million of the \$45.5 million will be recovered from SPP members and the remaining costs will be recovered through the District’s transmission rates.

COOPER NUCLEAR STATION LICENSE RENEWAL PROJECT AND EXTENDED POWER UPRATE

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 subsequent of the licensing renewal, along with early implementation projects. At this time, an additional, approximately \$58.5 million is anticipated for additional capital projects associated with the licensing renewal which the Board will act on at a future date. Final costs for the subsequent license renewal could be higher than the estimate due to numerous cost variables which have not been finalized. Upon approval of the subsequent 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. The District plans to submit the subsequent license renewal application in the second quarter of 2026 to the Nuclear Regulatory Commission (“NRC”) for review, with expected approval approximately 12 months later.

In October 2025, the Board authorized funding to pursue a feasibility study in 2026 for an Extended Power Uprate at Cooper Nuclear Station, which is expected to be completed in late 2026 or early 2027. Pending the results of that study, this multi-year major project is expected to culminate in full implementation in 2032 and would effectively increase power output of the station by 10-12% equating to approximately 80 MW to 100 MW of additional generation. The Cooper Nuclear Station Extended Power Uprate is projected to cost \$241.0 million. Final costs for the EPU could be higher than the estimate due to numerous cost variables which have not been finalized.

BEATRICE POWER STATION EXPANSION PROJECT

In order to address load growth and increases in the RAR, the District has also initiated the planning and development processes for capacity expansion at the Beatrice Power Station (the “Beatrice Power Station Expansion Project”), located northwest of Beatrice, Nebraska. The Beatrice Power Station Expansion Project will incorporate up to three new natural gas-fired CTs to obtain additional generation capacity of approximately 700 MW. The District is in negotiations for the purchase of CTs and will consider market dynamics to determine the final capacity options. The District is also in discussion with multiple contractors and intends to enter into an EPC contract in 2026 that includes all the work and procurement of equipment needed to build and commission the Beatrice Power Station Expansion Project. The District has not yet initiated the permitting process, including NPRB approval, of the Beatrice Power Station Expansion Project.

The Beatrice Power Station Expansion Project was included in the 2023 SPP generation interconnection process and will interconnect with the existing 345 kV transmission system by constructing approximately 45 miles of new 345 kV transmission lines that connect Beatrice Power Station, as expanded by the Beatrice Power Station Expansion Project, to both the Olive Creek substation and a planned new substation. Commercial operation is targeted for 2032 or later for full build out of all CTs.

ONE BIG BEAUTIFUL BILL ACT (“OBBBA”)

On July 4, 2025, the OBBBA was enacted into law. The OBBBA modifies numerous federal tax and spending provisions, including the consolidation and revision of certain clean energy tax credits, adjustments to business interest deduction limitations, and changes to incentives established under the Inflation Reduction Act (“IRA”) The OBBBA also rescinds grant funds for certain environmental, climate justice, greenhouse gas reduction, and low-carbon infrastructure projects or programs. The District continues to monitor the OBBBA and related guidance issued by the U.S. Department of Treasury and the Internal Revenue Service to evaluate potential implications on the District’s operations and potential future financial incentives.

45U ZERO-EMISSION NUCLEAR POWER PRODUCTION CREDIT

The IRA was signed into law in 2022, and amended by the OBBBA, which was signed into law in July 2025. The IRA allows not-for-profit public power utilities like the District to receive federal payments for a variety of generation projects through direct-pay subsidies. In 2025, the District worked with a nationally recognized tax firm to file a 2024 tax-year return for an elective payment on the Nuclear Power Production (45U) credit in the amount of approximately \$92 million. In January 2025, the Board approved regulatory accounting for the 45U credit received which, based upon Board direction, would defer the 45U revenues to a future period to cover futured designated nuclear, new generation, or other strategic initiative costs. The District received payment for the 2024 filing in December 2025, and plans to file a 2025 tax-year return in May of 2026 for the estimated amount of \$104 million. Current regulations provide this credit through 2032; however, future legislative changes, regulatory guidance or market prices may impact the District’s future direct-pay opportunities.

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 58.7% and 54.8% for 2025 and 2024, respectively. Non-carbon energy resources as a percentage of native load sales increased in 2025 compared to 2024 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/resilience, and sustainability. Major variables included CO₂, 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 EnergyWiseSM 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 the District’s participation in the SPP IM, 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 real gross state product increased by 2.2% between the third quarter of 2024 and the third quarter of 2025, 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 2.3% increase in real gross domestic product over the same 12-month period.

According to the Bureau, Nebraska experienced declines in “Administrative and Waste Management and Remediation Services” (-6.5%), “Wholesale Trade” (-5.2%), “Management of Companies and Enterprises” (-4.9%), “Mining, Quarrying, and Oil and Gas Extraction” (-3.8%), and “Retail Trade” (-2.6%). These declines were offset by increases in “Agriculture, Forestry, and Fishing” (33.2%), “Information” (7.9%), “Arts, Entertainment, and Recreation” (6.9%), “Professional, Scientific, and Technical Services” (5.5%), and “Healthcare and Social Services” (5.4%).

According to the Consumer Price Index for All Urban Consumers (“CPI-U”), the average annual inflation rate was 2.6% for 2025, down from 2.9% in 2024, and monthly inflation rates were 2.7% and 2.4% for December 2025 and January 2026, respectively. Currently, inflationary pressures remain as retail prices increase in response to lingering impacts of supply chain disruptions, labor shortages, and increased tariffs. However, there are some positives. Unemployment has remained steady, and consumers are less pessimistic about spending.

Increased geopolitical uncertainty in Central and South America, the Caribbean, and the Middle East may further disrupt supply chains as well as lead to increased energy prices, especially for oil and natural gas. Shifting tariff policies and growth in Artificial Intelligence (AI) and data center investment will have major economic impacts in 2026.

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 2024 value of 2.8% to 3.0% in 2025. This rate was well below the 2025 national average unemployment rate of 4.3%. Nebraska’s preliminary, seasonally adjusted unemployment rate was 3.0% in December 2025, up from the revised 2.9% in December 2024. Both numbers were well below the national December seasonally adjusted unemployment rates of 4.4% and 4.18% in 2025 and 2024, respectively. Nebraska’s revised December 2025 unemployment rate was the sixth 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:

- challenges associated with servicing new extremely large electric loads,
- effects of natural disasters including, but not limited to, tornadoes, floods, wildfires, windstorms, and other extreme weather-related events,
- changes from projected future load requirements,
- supply chain constraints and 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,
- inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy, fuel, and transmission capacity,
- effects of financial instability of various participants in the power market,
- climate change and the potential contributions made to climate change by coal-fired and other fossil-fueled generating units,
- challenges associated with additional renewable generation, including distributed generation,
- electrification of transportation sectors,
- issues relating to cyber and physical security,
- increasing costs and challenges building electric transmission facilities,
- 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 NPRB. 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, 2025 and 2024, 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 the District as of December 31, 2025 and 2024, 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* on pages 7 through 26 and *REQUIRED SUPPLEMENTARY INFORMATION* on pages 69 through 71 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* on page 6 and *SUPPLEMENTARY INFORMATION* on page 72, 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.

A handwritten signature in black ink, which appears to read "PricewaterhouseCoopers LLP". The signature is written in a cursive, flowing style.

Chicago, Illinois
April 9, 2026

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Statements of Net Position - Business-Type Activities

Nebraska Public Power District

As of December 31, (in 000's)

	2025	2024
ASSETS AND DEFERRED OUTFLOWS		
Current Assets:		
Cash and cash equivalents	\$ 3,307	\$ 3,569
Investments	911,354	711,601
Receivables, less allowance for doubtful accounts of \$530 and \$514, respectively	106,238	108,206
45U credit receivable	104,609	-
Fossil fuels, at average cost	23,866	33,504
Materials and supplies, at average cost	170,403	159,107
Prepayments and other current assets	15,908	17,859
	<u>1,335,685</u>	<u>1,033,846</u>
Special Purpose Funds:		
Construction funds	-	7,083
Debt service and reserve funds	80,157	87,537
Employee benefit funds	8,628	4,007
Supplemental decommissioning funds	13,585	10,376
Decommissioning funds	689,400	642,826
	<u>791,770</u>	<u>751,829</u>
Utility Plant, at Cost:		
Utility plant in service	5,456,047	5,353,129
Less reserve for depreciation	3,314,411	3,225,030
	<u>2,141,636</u>	<u>2,128,099</u>
Construction work in progress	671,760	356,528
Nuclear fuel, at amortized cost	129,883	153,227
	<u>2,943,279</u>	<u>2,637,854</u>
Other Long-Term Assets:		
Long-term capacity contracts	98,396	103,589
Unamortized financing costs	3,074	3,770
Equity investments	34,193	32,890
Net other postemployment benefit asset	52,074	43,733
Other	22,671	41,097
	<u>210,408</u>	<u>225,079</u>
Total Assets	<u>5,281,142</u>	<u>4,648,608</u>
Deferred Outflows of Resources:		
Regulatory Asset - ARO	180,737	206,861
Unamortized cost of refunded debt	1,091	1,783
Other postemployment benefits	62,700	69,140
	<u>244,528</u>	<u>277,784</u>
TOTAL ASSETS AND DEFERRED OUTFLOWS	<u>\$ 5,525,670</u>	<u>\$ 4,926,392</u>

Statements of Net Position - Business-Type Activities

Nebraska Public Power District

As of December 31, (in 000's)

	2025	2024
LIABILITIES, DEFERRED INFLOWS, AND NET POSITION		
Current Liabilities:		
Revenue bonds, current	\$ 62,815	\$ 78,030
Revolving credit agreements, current	-	250,314
Accounts payable and accrued liabilities	136,161	93,745
Accrued in lieu of tax payments	10,985	10,442
Accrued payments to retail communities	2,550	2,621
Accrued compensated absences	41,828	40,425
Other	28,746	30,325
	<u>283,085</u>	<u>505,902</u>
Long-Term Debt:		
Revenue bonds, net of current	757,646	831,507
Revolving credit agreements, net of current	532,120	-
	<u>1,289,766</u>	<u>831,507</u>
Other Long-Term Liabilities:		
Asset retirement obligation	883,893	860,997
Other	98,566	48,971
	<u>982,459</u>	<u>909,968</u>
Total Liabilities	<u>2,555,310</u>	<u>2,247,377</u>
Deferred Inflows of Resources:		
Unearned revenues	202,125	224,349
Other deferred inflows	651,254	397,485
	<u>853,379</u>	<u>621,834</u>
Net Position:		
Net investment in capital assets	1,692,659	1,618,342
Restricted	20,214	21,570
Unrestricted	404,108	417,269
	<u>2,116,981</u>	<u>2,057,181</u>
TOTAL LIABILITIES, DEFERRED INFLOWS, AND NET POSITION	<u>\$ 5,525,670</u>	<u>\$ 4,926,392</u>

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)

	2025	2024
Operating Revenues	\$ 1,154,555	\$ 1,163,637
Operating Expenses:		
Power purchased	183,610	189,834
Production:		
Fuel	156,926	144,973
Operation and maintenance	311,111	350,726
Transmission and distribution operation and maintenance	135,238	128,754
Customer service and information	23,358	22,492
Administrative and general	107,436	103,652
Payments to retail communities	34,223	32,164
Decommissioning	40,093	46,917
Depreciation and amortization	122,225	125,572
Payments in lieu of taxes	10,959	10,409
	<u>1,125,179</u>	<u>1,155,493</u>
Operating Income	<u>29,376</u>	<u>8,144</u>
Investment and Other Income:		
Investment income	62,300	59,516
Other income	1,921	2,708
	<u>64,221</u>	<u>62,224</u>
Change in Net Position Before Debt and Other Expenses	<u>93,597</u>	<u>70,368</u>
Debt and Related Expenses:		
Interest on revenue bonds	39,875	42,661
Allowance for funds used during construction	(13,410)	(9,046)
Bond premium amortization net of debt issuance expense	(9,657)	(10,629)
Interest on revolving credit agreements	16,989	10,567
	<u>33,797</u>	<u>33,553</u>
Change in Net Position	59,800	36,815
Net Position:		
Beginning balance	2,057,181	2,020,366
Ending balance	<u>\$ 2,116,981</u>	<u>\$ 2,057,181</u>

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)

	2025	2024
Cash Flows from Operating Activities:		
Receipts from customers and others	\$ 1,201,319	\$ 1,076,039
Other receipts	313	253
Payments to suppliers and vendors	(560,477)	(587,655)
Payments to employees	(375,599)	(345,356)
Net cash provided by operating activities	<u>265,556</u>	<u>143,281</u>
Cash Flows from Noncapital Financing Activities:		
Other receipts-45U	95,438	-
Net cash provided by noncapital financing activities	<u>95,438</u>	<u>-</u>
Cash Flows from Investing Activities:		
Proceeds from sales and maturities of investments	3,118,144	2,634,709
Purchases of investments	(3,307,011)	(2,621,554)
Income received on investments	40,638	38,458
Investment in TEA	252	(1,620)
Net cash provided by (used in) investing activities	<u>(147,977)</u>	<u>49,993</u>
Cash Flows from Capital and Related Financing Activities:		
Proceeds from revolving credit agreements	319,843	108,296
Capital expenditures for utility plant	(423,571)	(223,278)
Contributions in aid of construction and other reimbursements	54,057	28,458
Principal payments on revenue bonds	(78,030)	(65,110)
Interest payments on revenue bonds	(39,875)	(42,661)
Principal payments on revolving credit agreements	(38,037)	(5,752)
Interest payments on revolving credit agreements	(11,098)	(7,964)
Other non-operating revenues	3,432	4,305
Net cash used in capital and related financing activities	<u>(213,279)</u>	<u>(203,706)</u>
Net increase (decrease) in cash and cash equivalents	(262)	(10,432)
Cash and cash equivalents, beginning of year	3,569	14,001
Cash and cash equivalents, end of year	<u>\$ 3,307</u>	<u>\$ 3,569</u>

Statements of Cash Flows - Business-Type Activities

Nebraska Public Power District

For the years ended December 31, (in 000's)

	2025	2024
Reconciliation of Operating Income to Cash Provided By Operating Activities:		
Operating income	\$ 29,376	\$ 8,144
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation and amortization	122,225	125,572
Undistributed net revenue - The Energy Authority	-	(132)
Decommissioning, net of customer contributions	25,836	24,085
Amortization of nuclear fuel	37,176	29,858
Changes in assets and liabilities which provided (used) cash:		
Receivables, net	(206,862)	8,248
Fossil fuels	9,638	9,441
Materials and supplies	(11,296)	(13,695)
Prepayments and other current assets	19,516	(12,368)
Deferred outflows	273	278
Accounts payable and accrued payments to retail communities	12,294	15,879
Unearned revenues	(22,224)	(33,962)
Other deferred inflows	247,386	(14,684)
Other liabilities	2,218	(3,383)
Net cash provided by operating activities	<u>\$ 265,556</u>	<u>\$ 143,281</u>
Supplementary Non-Cash Capital Activities:		
Change in utility plant additions in accounts payable	<u>\$ 30,051</u>	<u>\$ 9,678</u>

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)

	2025	2024
Assets:		
Cash and cash equivalents	\$ 15,504	\$ 20,368
Receivables:		
Investment income	29	835
Investments	408,431	366,306
Total Assets	<u>423,964</u>	<u>387,509</u>
Liabilities:		
Payables:		
Benefits - healthcare	311	122
Benefits - life insurance	20	59
Investment expense	167	150
Professional, administrative and other expenses	324	47
Total liabilities	<u>822</u>	<u>378</u>
Net Position - Restricted for Other Postemployment Benefits	<u>\$ 423,142</u>	<u>\$ 387,131</u>

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)

	2025	2024
Additions:		
Contributions		
Employer	\$ 2,399	\$ 2,406
Investment Income:		
Net appreciation in fair value of investments	47,289	38,113
Interest, dividends and other income	7,666	7,747
Total investment income	<u>54,955</u>	<u>45,860</u>
Less: Investment expenses	<u>(1,108)</u>	<u>(1,063)</u>
Net investment income	<u>53,847</u>	<u>44,797</u>
Total additions	<u>56,246</u>	<u>47,203</u>
Deductions:		
Health care benefits	19,506	17,466
Life insurance benefits	183	247
Professional, administrative and other expenses	546	256
Total deductions	<u>20,235</u>	<u>17,969</u>
Change in Net Position	36,011	29,234
Net Position - Restricted for Other Postemployment Benefits		
Beginning balance	387,131	357,897
Ending balance	<u>\$ 423,142</u>	<u>\$ 387,131</u>

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 maintained on an accrual basis in accordance with generally accepted accounting principles in the United States (“GAAP”) issued by the Governmental Accounting Standards Board (“GASB”) applicable to governmental entities that use proprietary fund accounting.

The District Board has authority for establishing rates. Accounting guidance under GASB Statement No. 62 “Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements”, permits an entity with cost-based rates to defer certain costs or income that would otherwise be recognized when incurred to the extent that the rate-regulated entity is recovering or expects to recover such amounts in its billings.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the financial statements and related disclosures in these Notes. Actual results could differ from those estimates.

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 and Statements of Cash Flows.

E. *Fossil Fuel, Materials and Supplies* –

The District maintains inventories for fossil fuels and materials and supplies which are valued at average cost. Obsolete inventory is expensed and removed from inventory.

F. *Utility Plant, Depreciation, Amortization and Maintenance* –

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

The District records depreciation over the estimated useful life of the property primarily on a straight-line basis. Depreciation on utility plant was approximately 1.9% and 2.0% for the years ended December 31, 2025, and 2024. The District had fully depreciated utility plant, primarily related to Cooper Nuclear Station, which was still in service of \$1,618.7 million and \$1,643.2 million as of December 31, 2025, and 2024, 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 \$8.1 million and \$10.3 million in 2025 and 2024, respectively, which was included in depreciation and amortization expense. These utility plant additions, which were fully amortized, totaled \$243.8 million and \$237.1 million as of December 31, 2025 and 2024, respectively.

G. Allowance for Funds Used During Construction (“AFUDC”) –

This allowance, which represents the cost of funds used to finance construction, is recorded as a regulatory asset and amortized over the useful life of the associated capital asset. Regulatory accounting, GASB codification section Re10, *Regulated Operations*, is used to amortize these costs over their respective periods. 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 5.0%. For construction financed on a short-term basis, the rate was 3.5% and 4.0% for 2025 and 2024, 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 and recorded as fuel expense. 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.

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, 2025, and 2024 and activity for the years then ended (in 000’s):

	2025	2024
Unearned revenues, beginning of year	\$ 224,349	\$ 258,311
Surpluses	39,646	33,793
Use of prior period rate stabilization funds in rates	(61,870)	(67,755)
Unearned revenues, end of year	\$ 202,125	\$ 224,349

In 2025, the District worked with a nationally recognized tax firm to file a 2024 tax-year return for an elective payment on the 45U credit in the amount of approximately \$92 million. In January 2025, the Board approved regulatory accounting for the 45U credit received and interest earnings which, based upon Board direction, would defer the 45U revenues to a future period to cover future designated nuclear, new generation, or other strategic initiative costs. The District received payment for the 2024 filing in December 2025 and plans to file a 2025 tax-year return in 2026 for the estimated amount of \$104 million.

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

In 2025, the District collected approximately half of the costs of the 2026 Cooper Nuclear Station refueling and maintenance outage. This regulatory liability was included in Other deferred inflows on the Statements of Net Position and will be amortized through revenue during 2026, the year of the outage.

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 usable 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.

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 following table summarizes the balance of Other deferred inflows of resources as of December 31, 2025, and 2024 (in 000’s):

	2025	2024
45U Credits	\$ 199,645	\$ -
Non-nuclear decommissioning collections	92,843	79,525
DOE settlements	71,312	77,421
Cooper Nuclear Station reserve	69,346	69,346
Nuclear fuel disposal collections	69,234	62,782
Unrealized OPEB gains	60,308	69,519
Other regulatory and OPEB liabilities	35,989	11,158
Cooper Nuclear Station outage collections	26,000	-
Nuclear supplemental decommissioning	13,586	10,376
Settlements for termination of agreements	12,991	17,358
	<u>\$ 651,254</u>	<u>\$ 397,485</u>

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.

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. 102, *Certain Risk Disclosures*, was issued in December 2023. This Statement required 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 provided 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. The requirements of this Statement were implemented in 2025. This statement had no impact on the District’s financial position, results of operations or cash flows in 2025.

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.

GASB Statement No. 105, *Subsequent Events*, was issued in December 2025. The objective of this Statement is to improve the financial reporting requirements for subsequent events, thereby enhancing consistency in their application and better meeting the information needs of financial statement users. This Statement requires the date through which subsequent events have been evaluated to be disclosed and clarifies the subsequent events that constitute recognized and non-recognized events and establishes specific note disclosure requirements for non-recognized events. The requirements of this Statement are effective for the fiscal years beginning after June 15, 2026.

2. CASH AND INVESTMENTS:

Investments are recorded at fair value with the changes in the fair value of investments reported as Investment income in the accompanying Statements of Revenues, Expenses, and Changes in Net Position. The District had an unrealized net gain of \$1.6 million in 2025 and an unrealized net loss of \$1.2 million in 2024, 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):

	2025		2024	
	Fair Value	Weighted Average Maturity (Years)	Fair Value	Weighted Average Maturity (Years)
U.S. Treasury and government agency securities .	\$ 1,070,160	3.1	\$ 1,054,580	4.2
Corporate bonds	205,568	6.4	213,713	6.2
Municipal bonds	40,900	4.1	21,303	7.1
Cash and cash equivalents	389,803	0.1	177,403	0.1
Total cash and investments	<u>\$ 1,706,431</u>		<u>\$ 1,466,999</u>	
Portfolio weighted average maturity		<u>2.9</u>		<u>4.0</u>

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.

As of December 31, 2025, approximately 56.0% of corporate bonds and municipal bonds held by District were rated from A1 to Aaa, approximately 34.4% of corporate and municipal bonds held by the District were rated from Ba1 to Baa3, and approximately 9.6% were not rated. U.S. Treasury and government agencies securities are not considered to have credit risk. As of December 31, 2024, approximately 53.3% of corporate bonds and municipal bonds held by District were rated from A1 to Aaa, approximately 36.4% of corporate and municipal bonds held by the District were rated from Ba1 to Baa3, and approximately 10.3% were not rated. U.S. Treasury and government agencies securities are not considered to have credit risk. Moody’s ratings were used for the above analysis.

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.

Custodial Credit Risk – Investments - For an investment, custodial credit risk is a risk that, in the event of a failure of the counterparty, NPPD would be unable to recover the value of its investment securities in possession of an outside party. NPPD manages this risk by holding all investments in NPPD's name.

Concentration of Credit Risk – Concentration of credit risk is the risk associated with the amount of investments the District has with any one issuer. Investments issued or explicitly guaranteed by the U.S. government are excluded from this requirement. The District's investment policies managing revenue, construction, debt service and reserve, supplemental decommissioning and decommissioning funds manage concentration of credit risk by limiting investments in federal agency securities to no more than 25% of District's assets in any one federal agency. Investment authorization is measured at the time of acquisition.

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.

	<u>2025</u>	<u>2024</u>
Revenue funds - Cash and cash equivalents	\$ 3,307	\$ 3,569
Revenue funds - Cash equivalents in investments	342,080	156,507
Revenue funds - Investments	<u>569,274</u>	<u>555,094</u>
	<u>\$ 914,661</u>	<u>\$ 715,170</u>

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.

	<u>2025</u>	<u>2024</u>
Construction funds - Investments	\$ -	\$ 7,083

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 \$20.2 million and \$21.6 million as of December 31, 2025, and 2024, respectively. The District is required by the General Resolution to maintain a minimum of \$50.7 million in the Secondary Account and such minimum amount can be eliminated by the Board. Such accounts totaled \$52.7 million and \$51.8 million as of December 31, 2025, and 2024.

	<u>2025</u>	<u>2024</u>
Debt service and reserve funds - Investments	80,157	87,537
	<u>\$ 80,157</u>	<u>\$ 87,537</u>

The Employee benefit funds consist of a self-funded hospital-medical benefit plan for active employees only as of December 31, 2025, and 2024. The District pays 89.0% and 87.0% of the hospital-medical premiums with the employees paying the remaining 11.0% and 13.0% of the cost of such coverage for the years 2025 and 2024, respectively.

	<u>2025</u>	<u>2024</u>
Employee benefit funds - Cash and cash equivalents	\$ 8,628	\$ 4,007

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.

	<u>2025</u>	<u>2024</u>
Supplemental decommissioning funds - Cash and cash equivalents	\$ 13,585	\$ 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.

	<u>2025</u>	<u>2024</u>
Decommissioning funds - Cash and cash equivalents	\$ 22,203	\$ 2,944
Decommissioning funds - Investments	667,197	639,882
	<u>\$ 689,400</u>	<u>\$ 642,826</u>

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, 2025, and 2024.

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):

	2025			
	Level 1	Level 2	Level 3	Total
Revenue, special purpose funds, and supplemental decommissioning:				
U.S. Treasury and government agency securities	\$ -	\$ 649,432	\$ -	\$ 649,432
Cash and cash equivalents	367,600	-	-	367,600
Decommissioning funds:				
U.S. Treasury and government agency securities	-	420,728	-	420,728
Corporate bonds	-	205,568	-	205,568
Municipal bonds	-	40,900	-	40,900
Cash and cash equivalents	19,117	3,086	-	22,203
	<u>\$ 386,717</u>	<u>\$ 1,319,714</u>	<u>\$ -</u>	<u>\$ 1,706,431</u>

	2024			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding 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
	<u>\$ 177,403</u>	<u>\$ 1,289,596</u>	<u>\$ -</u>	<u>\$ 1,466,999</u>

4. UTILITY PLANT:

Utility plant activity for the year ended December 31, 2025, was as follows (in 000's):

	December 31, 2024	Increases	Decreases	December 31, 2025
Nondepreciable utility plant:				
Land and improvements	\$ 77,404	\$ 20	\$ -	\$ 77,424
Construction in progress	356,528	426,348	(111,116)	671,760
Total nondepreciable utility plant	<u>433,932</u>	<u>426,368</u>	<u>(111,116)</u>	<u>749,184</u>
Nuclear fuel*	<u>153,227</u>	<u>13,831</u>	<u>(37,175)</u>	<u>129,883</u>
Depreciable utility plant:				
Generation - Fossil	1,731,216	20,311	(7,046)	1,744,481
Generation - Nuclear	1,332,735	9,370	(325)	1,341,780
Transmission	1,518,765	56,356	(2,397)	1,572,724
Distribution	288,431	16,705	(8,217)	296,919
General	404,578	22,144	(5,664)	421,058
SBITA	-	1,661	-	1,661
Total depreciable utility plant	<u>5,275,725</u>	<u>126,547</u>	<u>(23,649)</u>	<u>5,378,623</u>
Less reserve for depreciation and amortization ...	<u>(3,225,030)</u>	<u>(113,030)</u>	<u>23,649</u>	<u>(3,314,411)</u>
Depreciable utility plant, net	<u>2,050,695</u>	<u>13,517</u>	<u>-</u>	<u>2,064,212</u>
Utility plant activity, net	<u>\$ 2,637,854</u>	<u>\$ 453,716</u>	<u>\$ (148,291)</u>	<u>\$ 2,943,279</u>

* Nuclear fuel decreases represented amortization of \$37.2 million recorded in fuel expense.

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	<u>340,892</u>	<u>185,479</u>	<u>(92,439)</u>	<u>433,932</u>
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 and amortization ...	(3,182,028)	(115,046)	72,044	(3,225,030)
Depreciable utility plant, net	<u>2,071,956</u>	<u>(21,261)</u>	<u>-</u>	<u>2,050,695</u>
Utility plant activity, net	<u>\$ 2,551,805</u>	<u>\$ 208,346</u>	<u>\$ (122,297)</u>	<u>\$ 2,637,854</u>

* Nuclear fuel decreases represented amortization of \$29.9 million recorded in fuel expense.

The District has entered into subscription-based information technology arrangements (“SBITAs”) for enterprise software systems. Subscription assets are reported as intangible assets and amortized over the subscription term. The Board authorized the use of regulatory accounting for recording SBITAs, in such the District has recorded a regulatory asset as of December 31, 2025 and a right-to-use liability for future payments.

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 \$75.4 million and \$71.0 million as of December 31, 2025, and 2024, respectively. The unamortized amount of the plant capacity contract was \$102.7 million and \$106.3 million as of December 31, 2025, and 2024, respectively, of which \$4.4 million was included in Prepayments and other current assets as of December 31, 2025, and 2024. The District's share of NC2 working capital was also included in Prepayments and other current assets and was \$7.5 million and \$8.4 million as of December 31, 2025, and 2024, 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 \$85.1 million and \$82.8 million as of December 31, 2025, and 2024, respectively. The unamortized amount of the Central capacity contract was \$1.6 million and \$3.9 million as of December 31, 2025, and 2024, respectively, of which \$1.6 million and \$2.3 million was included in Prepayments and other current assets as of December 31, 2025, and 2024.

The District has an agreement whereby Central makes available all the production of the facility and the District pays all costs of operating and maintaining the facility plus a charge based on the amount of energy delivered to the District. Power purchased costs related to Central were \$1.9 million and \$2.2 million in 2025 and 2024, respectively.

6. INVESTMENTS IN TEA:

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 18.75% and 17.65% as of December 31, 2025, and 2024. In addition to the District, the following utilities have interests of 18.75% each as of December 31, 2025: American Municipal Power, Inc.; JEA (Florida); Grand River Dam Authority; and South Carolina Public Service Authority (a.k.a. Santee Cooper). City Utilities of Springfield, Missouri has an interest in TEA of 6.25% as of December 31, 2025.

Such investment was \$34.2 million and \$32.8 million as of December 31, 2025, and 2024, 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, 2025, 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, 2025, and 2024.

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, 2025. In addition to the District, the following utilities have interests of 20.0% each as of December 31, 2025: American Municipal Power, Inc.; City Utilities of Springfield, Missouri, JEA (Florida); and Santee Cooper.

Such investment was \$0.4 million and \$0.1 million as of December 31, 2025, and 2024, respectively. 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, 2025, and 2024, and debt activity for 2025 (in 000's):

	Total Debt at December 31, 2024			Total Debt at December 31, 2025			Long-Term Debt at December 31, 2025	Current Liabilities at December 31, 2025
		Increases	Decreases					
Revenue bonds	\$ 909,537	\$ -	\$ (89,076)	\$ 820,461		\$ 757,646	\$ 62,815	
Commercial paper notes	-	199,000	-	\$ 199,000		199,000	-	
Revolving credit agreements	250,314	120,843	(38,037)	333,120		333,120	-	
Total debt activity	<u>\$ 1,159,851</u>	<u>\$ 319,843</u>	<u>\$ (127,113)</u>	<u>\$ 1,352,581</u>		<u>\$ 1,289,766</u>	<u>\$ 62,815</u>	

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			Total Debt at December 31, 2024			Long-Term Debt at December 31, 2024	Current Liabilities at December 31, 2024
		Increases	Decreases					
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	<u>\$ 1,134,654</u>	<u>\$ 108,296</u>	<u>\$ (83,099)</u>	<u>\$ 1,159,851</u>		<u>\$ 831,507</u>	<u>\$ 328,344</u>	

General Revenue Bonds

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, 2025, are as follows (in 000's):

Year	Interest Payments	Principal Payments	Debt Service Payments
2026	\$ 36,503	\$ 62,815	\$ 99,318
2027	33,772	63,295	97,067
2028	27,334	203,860	231,194
2029	21,211	44,990	66,201
2030	19,046	49,640	68,686
2031-2035	64,047	194,250	258,297
2036-2040	23,875	108,180	132,055
2041-2045	4,298	42,350	46,648
Total Payments	<u>\$ 230,086</u>	<u>\$ 769,380</u>	<u>\$ 999,466</u>

In 2010, the District issued taxable Build America Bonds. Pursuant to the requirements of the Balanced Budget and Emergency Deficit Control Act of 1985, as amended, congressional action reduced the 35.0% interest subsidy, on the District's 2010 Series A. Reductions of 5.7% have occurred annually since 2021 for the fiscal years ended September 30.

There were outstanding principal amounts aggregating \$2.4 million and \$2.9 million from legal defeasances of General Revenue Bonds, 2017 Series A, as of December 31, 2025, and 2024, respectively.

Tax-Exempt Revolving Credit Agreement (“TERCA”)

The District has entered into a TERCA with a commercial bank to provide for loan commitment to the District up to an aggregate amount not to exceed \$150.0 million. The TERCA was amended and restated on September 2, 2025, and expires on March 2, 2029. Total capitalization is defined as the sum of all outstanding debt and the net position. As of December 31, 2025 and 2024, the capitalization ratio of the District was 15.3% and 7.8% respectively, which is below the maximum of 25.0%.

The District had an outstanding balance under the TERCA of \$109.4 million and \$70.4 million as of December 31, 2025, and 2024, respectively. As such, the remaining credit available under TERCA was \$40.6 million and \$79.6 million as of December 31, 2025, and 2024, 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 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 Taxable Revolving Credit Agreement (“TRCA”) mentioned below or the Side-by-Side Revolving Credit Agreement (“SBSRCA”) mentioned below is converted to a term loan or a reimbursement obligation is due under the Side-by-Side Reimbursement Agreement (“SBSRA”) or the SPP Reimbursement Agreement mentioned below, 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 \$300.0 million. The TRCA was amended and restated on July 1, 2025, and expires on June 30, 2028.

The District had outstanding balances under the TRCA of \$223.7 million and \$179.9 million, as of December 31, 2025 and 2024, respectively. As such, the remaining credit available under TRCA was \$76.3 and \$120.1 million as of December 31, 2025, and 2024, respectively. The outstanding amount is anticipated to be retired by future collections through electric rates and the issuance of revenue bonds. The carrying value approximates market value.

The 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 TERCA, or the SBSRCA is converted to a term loan or a reimbursement agreement obligation is due under the SBSRA or the SPP Reimbursement Agreement, 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 SBSRCA with a commercial bank and a SBSRA with a commercial bank with respective termination dates of October 15, 2027, unless such date is extended or earlier terminated. 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 \$544.4 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 15, 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 \$544.4 million, but the amounts drawn under the side-by-side credit agreements cannot exceed \$544.4 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.

As of December 31, 2024, the District had not borrowed any funds under the SBSRCA nor issued any commercial paper. As of December 31, 2025, the District had an outstanding balance of commercial paper of \$199.0 million and letter of credit under SBSRA of \$216.7 million to support the sale of commercial paper notes. The District expects to retire amounts outstanding from time to time under the SBSCRA and commercial paper by collections through electric rates and the issuance of General Revenue Bonds.

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, or SBSRCA is converted to a term loan or a reimbursement obligation is due under the SBSRA or the SPP Reimbursement Agreement, 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-".

SPP Reimbursement Agreement

The District entered into the SPP Reimbursement Agreement on September 2, 2025, with a commercial bank to secure its financial obligations under a Credit and Security Agreement with SPP. The SPP Reimbursement Agreement provides for the issuance of Letters of Credit in favor of SPP up to an aggregate amount not to exceed \$100.0 million. The SPP Reimbursement Agreement terminates on September 2, 2026, but is subject to automatic extension through September 2, 2028. As of December 31, 2025, there were letters of credit outstanding under the SPP Reimbursement Agreement in the aggregate amount of \$69.7 million.

The obligation of the District to pay its obligations pursuant to the SPP Reimbursement Agreement is payable from the Pledged Property subject and subordinate to the pledge of Pledged Property to the payment of the General Revenue Bonds. However, if any of the TRCA, TERCA or the SBSRCA is converted to a term loan or a reimbursement obligation is due under the SBSRA, the payment obligation under the SPP Reimbursement Agreement would be on a parity with the District's obligation to pay the General Bonds

The SPP Reimbursement Agreement defines an Event of Default which may result in the declaration of the obligations of the District under the SPP Reimbursement Agreement to be due and payable immediately. An Event of Default includes a failure to make any payment of its obligations under the SPP Reimbursement Agreement, an extended default in the performance of or compliance with any term or covenant contained in the SPP Reimbursement Agreement or an event of default under the General Bond Resolution.

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

December 31,	Interest Rate	2025	2024
General Revenue Bonds:			
2010 Series A Taxable Build America Bonds:			
Term Bonds: 2025–2029	5.323%	\$ 22,110	\$ 27,985
2030–2042	5.423%	54,190	54,190
2012 Series B:			
Serial Bonds: 2025–2032	2.875% - 3.375%	3,965	4,465
Term Bonds: 2033–2036	3.625%	2,320	2,320
2037–2042	3.625%	4,155	4,155
2015 Series A-1 Serial Bonds 2025–2034	3.000% - 5.000%	78,820	92,100
2016 Series A:			
Serial Bonds: 2025–2035	3.125% - 5.000%	29,430	44,395
Term Bonds: 2036–2040	5.000%	5,595	5,595
2016 Series B:			
Serial Bonds: 2028–2036	5.000%	64,570	64,570
Term Bonds: 2037–2039	5.000%	1,165	1,165
2016 Series C Serial Bonds 2025–2035	5.000%	31,560	36,770
2016 Series D:			
Serial Bonds: 2025–2035	3.000% - 5.000%	13,585	14,625
Term Bonds: 2036–2040	5.000%	9,505	9,505
2041–2045	5.000%	12,140	12,140
2016 Series E Taxable Serial Bonds 2025–2033	2.752% - 3.567%	39,490	43,790
2017 Series A Serial Bonds 2025–2027	3.000%	595	1,200
2017 Series B Serial Bonds 2025–2027	5.000%	12,305	18,030
2019 Series A Serial Bonds 2025–2034	5.000%	23,620	25,705
2019 Series B-1 Taxable Serial Bonds 2025–2028	2.421% - 2.593%	32,175	44,980
2019 Series B-2 Taxable Serial Bonds 2025–2028	2.421% - 2.593%	6,770	10,595
2021 Series A Serial Bonds 2025–2039	5.000%	65,315	65,315
2021 Series B Serial Bonds 2028–2040	5.000%	50,580	50,580
2021 Series C Serial Bonds 2025–2031	5.000%	35,930	43,745
2021 Series D:			
Serial Bonds: 2025–2026	5.000%	1,130	1,130
Term Bonds: 2041–2043	4.000%	18,720	18,720
2023 Series A Term Bonds 2028	5.000%	149,640	149,640
Total par amount of General Revenue Bonds		<u>769,380</u>	<u>847,410</u>
Unamortized premium net of discount		51,081	62,127
		<u>820,461</u>	<u>909,537</u>
Less – current maturities of General Revenue Bonds		(62,815)	(78,030)
Long-term General Revenue Bonds		<u>\$ 757,646</u>	<u>\$ 831,507</u>

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 \$11.0 million and \$10.4 million for December 31, 2025 and 2024, 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	2025	2024
Cooper Nuclear Station license termination costs	\$ 862,983	\$ 840,459
GGs and Sheldon ash landfills	11,863	11,701
Ainsworth	8,047	7,837
Underground storage tanks	<u>1,000</u>	<u>1,000</u>
	<u>\$ 883,893</u>	<u>\$ 860,997</u>

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 cessation of plant operations in 2034; and 2) safe storage for 60 years after cessation of plant operations. 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 2.0% and 2.9% for the years 2025 and 2024, respectively. Nuclear decommissioning fund balances were \$689.4 million and \$642.8 million as of December 31, 2025, and 2024, 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 of \$13.6 million and \$10.4 million as of December 31, 2025, and 2024, respectively.

The District is required by the Environmental Protection Agency (“EPA”) and the Nebraska Department of Water, Energy, and Environment (“NDWEE”) 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. NDWEE provided inflation factors based on the Implicit Price Deflator for the Gross Domestic Product of 2.7% and 2.4% for 2025 and 2024, respectively. The District provided guarantees and financial assurance through correspondence and supporting information to NDWEE. The costs in rates plus interest for the decommissioning of the ash landfills were \$0.6 million and \$0.7 million for 2025 and 2024, 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 2025 and 2024 ARO was based on an external study completed in 2021 for costs using one scenario. There are no legally required funding and assurance provisions associated with this ARO. The costs included in rates plus interest for the decommissioning of the Ainsworth Wind Energy Facility were \$1.5 million and \$1.6 million for 2025 and 2024, respectively. The rate collections and interest reduced the related deferred outflow for the Ainsworth Wind Energy Facility.

The District is required by the NDWEE 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 NDWEE. 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 2,076 and 2,030 active Plan members as of December 31, 2025, and 2024, 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 \$21.5 million and \$20.2 million for 2025 and 2024, respectively. The District's matching contributions were \$19.0 million and \$18.1 million for 2025 and 2024, respectively. Total contributions of \$2.1 million and \$2.0 million were accrued in accounts payable and accrued liabilities as of December 31, 2025 and 2024, 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 743 and 672 active Plan members as of December 31, 2025 and 2024, 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 \$4.1 million and \$3.2 million for 2025 and 2024, 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 eligible retired NPPD employees, their spouses, and dependents. The Plan also provides postemployment hospital-medical, dental, and life insurance benefits to 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 Health Reimbursement Account (“HRA”). The HRA benefit was approved by the Board in January 2020 with an effective date of January 1, 2021. The addition of the HRA expanded the availability of benefits to retirees hired from January 1, 1999 through December 31, 2003, and eligible employees hired on or after January 1, 2004 and retired after January 1, 2020. The HRA benefit is delivered to the retiree through a HRA and provides reimbursements for applicable healthcare premiums up to an annual amount of \$4,456 and \$2,228 for pre-Medicare and Medicare eligible retirees, respectively, for 2024. In November 2024, the Board authorized the President and Chief Executive Officer of the District to approve and authorize the annual adjustments available through the HRA. The President and Chief Executive Officer authorized 3.0% increases to the HRA benefits effective January 1, 2025. As a result, the annual benefits amounts increased from \$4,456 to \$4,590 for pre-Medicare retirees and from \$2,228 to \$2,295 for Medicare eligible retirees. The President and Chief Executive Officer authorized an increase in the annual amounts for 2026 to \$4,820 for pre-Medicare retirees and to \$2,410 for Medicare eligible retirees. The District also provided a postemployment death benefit of \$5,000 for qualifying retirees prior to December 31, 2025. Effective January 1, 2026, the District increased the postemployment death benefit to \$10,000 for qualifying retirees.

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 pre-Medicare premium costs for retiree and dependents; District share of premiums capped when Medicare eligible
Hired January 1, 1999 to December 31, 2003	District and retiree share in pre-Medicare premium costs for retiree and dependents; For employees active as of January 1, 2020, retiree eligible for HRA when Medicare eligible
Hired January 1, 2004 and after	For employees active as of January 1, 2020, retiree only eligible for pre-Medicare and Medicare eligible HRA

Employees Covered by Benefit Terms

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

	2025	2024
Active employees	1,994	1,959
Inactive employees or beneficiaries in retirement status	1,516	1,486
Inactive employees or beneficiaries in long-term disability status	32	42
Total employees covered by benefit terms	3,542	3,487

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

	2025	2024
Active employees	1,994	1,959
Inactive employees in retirement status	1,379	1,358
Inactive employees in long-term disability status	36	46
Total employees covered by benefit terms	3,409	3,363

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 2025 and 2024. The District OPEB contributions were \$2.4 million for 2025 and 2024.

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 \$0.8 million and \$0.7 million for 2025 and 2024, 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, 2025, and January 1, 2024. 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, 2025 and 2024, actuarial valuation were based on the results of an actuarial experience study completed during 2023. The total OPEB liability in the January 1, 2025, and 2024, 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: 8.6% initial for 2025, ultimate 4.5% Post-Medicare: 9.7% initial for 2025, ultimate 4.5% Pre-Medicare: 7.6% initial for 2024, ultimate 4.5% Post-Medicare: 8.5% initial for 2024, ultimate 4.5%
HRA increase rate	3.0%
Administrative cost trend	3.0%
Inflation	2.3% for 2025 and 2024
Salary increases	4.0%
Investment rate of return	6.25% for 2025 and 2024, net of investment expense, including inflation
Discount rate	6.25% for 2025 and 2024, 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 2025 and 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.
Participation rate	95.0%

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

Asset Class	Target Allocation	Long-Term Expected Real Rate of Return	
		2025	2024
Equity and Real Estate	70%	7.3%	7.3%
Fixed Income	30%	5.1%	4.2%
Total	100%	6.9%	6.7%

Discount Rate

The discount rate used to measure the total OPEB liability was 6.25% for the actuarial valuations as of January 1, 2025 and 2024, 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, 2025, and the changes during this period, based on the valuation measurement date of January 1, 2025 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB (Asset) Liability (a-b)
Balances at January 1, 2024	\$ 313,736	\$ 357,897	\$ (44,161)
Changes for the year:			
Service cost	1,929	-	1,929
Interest	19,184	-	19,184
Differences between expected and actual experience	1,635	-	1,635
Changes of assumptions	15,895	-	15,895
Contributions - employer	-	2,406	(2,406)
Net investment income	-	44,797	(44,797)
Benefit payments	(17,714)	(17,714)	-
Administrative expense	-	(255)	255
Net changes	<u>20,929</u>	<u>29,234</u>	<u>(8,305)</u>
Balances at January 1, 2025	<u>\$ 334,665</u>	<u>\$ 387,131</u>	<u>\$ (52,466)</u>

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, 2025 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB (Asset)/Liability	<u>\$ (13,143)</u>	<u>\$ (52,466)</u>	<u>\$ (85,652)</u>

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 7.6% initial to 3.5% ultimate, Post-Medicare ranging from 8.7% initial to 3.5% ultimate) or 1-percentage-point higher (Pre-Medicare ranging from 9.6% initial to 5.5% ultimate, Post-Medicare ranging from 10.7% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 8.6% initial to 4.5% ultimate, Post-Medicare ranging from 9.7% initial to 4.5% ultimate) at the measurement date of January 1, 2025 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB (Asset)/Liability	<u>\$ (83,441)</u>	<u>\$ (52,466)</u>	<u>\$ (16,017)</u>

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)

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, 2024 (in 000's):

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

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

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 \$8.7 million for 2025, 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 \$2.1 million for 2025.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2025 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	\$ 2,372	\$ 15,207
Changes in assumptions	22,538	5,262
Net difference between actual and expected earnings	-	4,448
Contributions made during the year ended December 31, 2025	2,399	-
	<u>\$ 27,309</u>	<u>\$ 24,917</u>

The deferred outflows of resources related to the contributions made during the year ended December 31, 2025, will be recognized in the actuarial valuation with a measurement date of January 1, 2026. 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
2026	\$ (475)
2027	7,765
2028	(8,726)
2029	(3,668)
2030	3,034
Total Thereafter	2,062

OPEB expense was negative \$13.4 million for 2024, 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 \$2.4 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
Net difference between actual and expected earnings	15,189	-
Contributions made during the year ended December 31, 2024	2,406	-
	<u>\$ 31,242</u>	<u>\$ 31,621</u>

The deferred outflows of resources related to the contributions made during the year ended December 31, 2024, were 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)
Total Thereafter	456

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 \$219.2 million at December 31, 2025. These contracts expire at various times through the end of 2032. 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 2036. 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 \$436.0 million through the 2032 reload.

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 of 23.7%. No such default has occurred to date.

The District and Lincoln have entered into a participation power sales agreement, as amended, for the sale to Lincoln of 8.0% of the net power and energy that can be produced by Gerald Gentleman Station. In return, Lincoln is required to pay 8.0% of all costs (excluding fuel costs) attributable to Gerald Gentleman Station. The cost of fuel is based on the amount of energy scheduled by Lincoln. In addition, the District is required to provide substitute energy to Lincoln under certain circumstances. This agreement is to terminate upon the later of the last maturity of the debt attributable to Gerald Gentleman Station or the date on which the District retires such station from commercial operation.

The District has wholesale power purchase commitments with Western which consist of 148.5 MW of firm power and 287 MW of firm peaking power from the Upper Great Plains Region through 2050, and approximately 4 MW of firm power from the Rocky Mountain Region through 2054. The District also receives and pays for approximately 4 MW of firm power from the Upper Great Plains Region for pass through to four Native American tribes through 2050. The annual minimum payments of these wholesale purchase commitments were \$33.6 million for 2025. The annual minimum future payments are approximately \$35.7 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 ended on September 30, 2025. In addition, the District has power purchase agreements with seven wind facilities having a total nameplate capacity of 433 MW. These agreements are for terms ranging from 20 to 30 years and require the District to purchase all the electric power output of these wind facilities and terminate between 2029 and 2054. The District has entered into power sales agreements to sell 171 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 2025 accredited net capacity of 33.0 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.

The District has a power purchase contract with Loup to purchase the energy and capacity produced by Loup’s hydroelectric system. The contract continues through December 31, 2060. The hydroelectric contract may be terminated by Loup or the District with at least five years notice to the other party, or if the wholesale power contract between the District and Loup is terminated.

**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 85.7% of total retail PRO Agreement revenues for 2025. 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 35 municipalities.

Effective January 1, 2026, the District entered into new wholesale contracts that have a term that extends to 2060. The 2026 Contracts replace wholesale contracts that were entered into in 2016. The 2016 Contracts are to continue in force after such 20-year term from year to year 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 and after the 15th year of the term of the 2016 Contracts. As of March 31, 2026, wholesale customers being served under the 2026 Contract include 18 public power districts, one cooperative, and 34 municipalities. Sixteen of the public power districts and the one cooperative are served under one contract with the Nebraska Electric Generation and Transmission Cooperative, Inc. Wholesale customers being served under the 2016 Contract include four public power districts and one municipality.

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 2020 to 2024 set forth in the CFC Data:

CFC Data	
Year	Percentile
2020	23.2%
2021	12.4%
2022	11.7%
2023	16.7%
2024	12.5%

The 2026 Contracts with these wholesale customers provide for the District to sell and such wholesale customers to purchase their total demand and energy requirements, subject to certain exceptions from the District. The 2026 Contracts include provisions relating to a wholesale customer’s right to terminate its 2026 Contract on or after January 1, 2036, or to cap its purchases from the District under its 2026 Contract on or after January 1, 2036.

The 2026 Contracts allow a wholesale customer to terminate its 2026 Contract on or after January 1, 2036, upon providing the District three years written notice to the District at any time after January 1, 2032, and upon payment of an Exit Fee (as hereinafter defined). The termination of a wholesale customer’s 2026 Contract is effective at the end of the day on the first December 31st at least 36 Months following the District’s receipt of the notice of termination (the “Termination Date”). The earliest Termination Date is January 1, 2036.

A wholesale customer's Exit Fee will be determined based on the wholesale customer's allocable share of the calculation of sum of (i) Outstanding Production Debt and (ii) Power Purchase Agreements ("PPA")/Power Sales Contracts ("PSC") stranded costs/ benefits. The Exit Fee will be reduced by amounts of uncommitted credits in the Rate Stabilization Account allocable to production and mitigated stranded costs under the PPAs and PPCs, as calculated in accordance with the 2026 Contracts. Any wholesale customer that executed its 2026 Contract on or before October 31, 2025 may reduce their Exit Fee by Production Debt Offsets. The Exit Fee will be used to pay Outstanding Production Debt and PPA/PSC obligations that the District incurred or executed prior to the wholesale customer giving the required notice to terminate pursuant to its 2026 Contract. The allocable share of a departing wholesale customer's Exit Fee will be based on the District's total production revenue over the most recent three calendar year periods prior to the applicable Termination Date for all wholesale customers purchasing wholesale power supply service from the District under the 2026 Contracts and the 2016 Contracts, if applicable.

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 new substation adjacent to an existing 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 generation in an area of the state that lacks sufficient transmission access. The R-Project construction was currently delayed as of December 31, 2025, because of the outcome of litigation, which is discussed further in this Note in section 12.F., *Environmental, Endangered Species Act*.

Due to significant delays and difficulties encountered in the Section 106 consultation process, the District requested coverage under the Department of the Interior's Emergency Process for Section 106 Compliance on August 22, 2025. The Department of the Interior approved that request on January 13, 2026, which initiated a seven-day Section 106 consultation period under the Emergency Process that concluded on January 20, 2026. The USFWS issued the Notice of Availability of the Final SEIS for the R-Project on January 30, 2026, and issued a Record of Decision and new ITP on February 10, 2026.

On March 3, 2026, various petitioners filed a petition for review in the U.S. District Court for the District of Colorado against certain officials at the USFWS, at the Department of the Interior and at the Advisory Council on Historic Preservation ("ACHP") challenging USFWS's and ACHP's actions authorizing the R-Project to proceed. Said petitioners have requested the court (i) vacate the ITP based on the USFWS's use of ACHP's Emergency Procedures for National Historic Preservation Act Section 106 Compliance and (ii) enjoin USFWS's authorization of R-Project incidental take of the ABB or its habitat from R-Project construction activities pending the completion of a renewed NHPA Section 106 process. On March 13, 2026, the District filed a motion to intervene. On March 25, 2026, the petitioners filed a motion for a preliminary injunction seeking to enjoin the USFWS, ACHP, and the District in order to preserve the status quo and prevent any construction pending a determination on the merits.

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.

In November 2025 the estimated cost approved by SPP for the R-Project is \$670.0 million. The estimated cost of the R-Project, so approved by SPP, became the new baseline for the R-Project, which SPP will adjust for escalation on an annual basis. The District will develop an updated cost estimate after having obtained the necessary permits and prior to resuming construction as noted below. The District's current estimated cost for the R-Project is \$835.1 million (including escalation) and is expected to be completed within 20% of the escalated baseline, thus approval from SPP would not be required. The District is responsible for constructing and funding the R-Project; however, approximately 95% of the final cost will be recovered from SPP members and the remaining costs will be recovered through the District's transmission rates.

The District awarded a contract for the construction of the R-Project in January 2019. The District has spent approximately \$176.0 million through December 31, 2025, for design, construction mobilization, purchase of lattice tower steel, and easement acquisitions. Major construction activities for the R-Project are not expected to commence before the second quarter of 2026 with an anticipated in-service date approximately two years after construction begins.

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. The District is pursuing a subsequent license renewal application to renew the operating license an additional 20 years to January 18, 2054.

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, encompassing the loading of 488 used fuel assemblies into 8 dry used fuel storage casks, began in September 2025 and was completed in November 2025.

As part of a settlement reached in 1989 of various disputed matters between General Electric (“GE”) and the District, GE has agreed 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. The District and DOE are currently negotiating an additional three-year extension. Settlements from the DOE for damages totaled \$150.1 million for the years 2009 through 2025. 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 \$71.3 million and \$77.4 million as of December 31, 2025 and 2024, 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 \$69.2 million and \$62.8 million as of December 31, 2025 and 2024, respectively.

Under the provisions of the Federal Price Anderson Act, the District and all other licensed nuclear power plant operators within the United States may, in the event of a nuclear incident at any nuclear generating plant in the United States, 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 quarterly 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 the third quarter 2025, 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, the 250 VDC A emergency station batteries were replaced. 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 \$26.0 million as of December 31, 2025, and will be eliminated through revenue recognition during the 2026 outage year.

The IRA allows not-for-profit public power utilities like the District to potentially receive federal payments for a variety of generation projects through direct-pay subsidies. In 2025, the District worked with a nationally recognized tax firm to file a 2024 tax-year return for an elective payment on the 45U credit in the amount of approximately \$92 million. In January 2025, the Board approved regulatory accounting for the 45U credit received which, based upon Board direction, would defer the 45U revenues to a future period to cover futued designated nuclear, new generation, or other strategic initiative costs. The District received payment for the 2024 filing in December 2025, and plans to file a 2025 tax-year return in 2026 for the estimated amount of \$104 million.

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. NDWEE establishes the compliance requirements through the issuance of National Pollutant Discharge Elimination System (“NPDES”) permits. The NDWEE issued the District six NPDES permits to Gerald Gentleman Station, Sheldon Station, Cooper Nuclear Station, Beatrice Power Station, Canaday Station, and the North Platte Office Building. Four of these facilities have storm water management plans. Cooper Nuclear Station and Gerald Gentleman Station have received Section 316(a) waivers.

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 NDWEE determined that the current entrainment technology was the BTA at Cooper Nuclear Station and Gerald Gentleman Station. The District subsequently selected and recommended screen modification to the NDWEE that were approved by the NDWEE and incorporated into the respective NPDES permits. The initial designs and engineering plans for the modified traveling screens were approved by the NDWEE. The modifications for Cooper Nuclear Station were installed in June 2025, and modifications for Gerald Gentleman Station were installed in August 2025. Upon installation of the screens, the District began a two-year optimization study at Cooper Nuclear Station and Gerald Gentleman Station.

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 sets 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 and byproducts associated with steam electric power generation: flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke.

While the District facilities subject to the ELG rule are Cooper Nuclear Station, Gerald Gentleman Station, Sheldon Station, and Canaday Station, this rule change only impacts Sheldon Station. Sheldon Station was 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 completed the installation in December 2025.

In April 2024, the EPA finalized a revision of the “Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category”. The rule requires a zero liquid discharge (“ZLD”) system by December 31, 2029, at Sheldon Station. In December 2025, the EPA issued a final rule extending the deadline for installing a ZLD system to December 31, 2034. The District will continue to monitor the ELG and associated rulemakings.

Air – Greenhouse Gas rules

On October 23, 2015, the EPA published the final Clean Power Plan (“CPP”) rule addressing carbon dioxide (“CO₂”) reductions from existing fossil-fueled power plants in the Federal Register. 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 finalized new CO₂ regulations for electric generation facilities which utilize natural gas, coal, or oil. The final regulations require varying compliance obligations depending on 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 for certain large, baseload natural gas plants. Co-firing with natural gas is an option for certain coal plants and co-firing with green hydrogen would be an option for certain natural gas plants. On June 17, 2025, the EPA proposed repeal of the carbon pollution standards for existing coal-fired and new natural gas fired electric utility generating units.

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-PM_{2.5}), Sulfur Dioxide (“SO₂”), 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 NDWEE for information pertaining to the second planning phase (2018-2028). Based on screening performed by Central States Air Resources Agencies, the NDWEE determined that Gerald Gentleman Station may contribute to the visibility impairment at multiple Class I areas. The NDWEE ICR requested information regarding the cost to install and operate four SO₂ control options at Gerald Gentleman Station Units No. 1 and No. 2. The District submitted the initial response to the NDWEE ICR on November 2, 2020, and supplemental response on December 30, 2020. Comprehensive air quality visibility modeling submitted by the District to NDWEE 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 August 1, 2024, the EPA issued a proposal to revise the first planning period plan for Gerald Gentleman Station to require scrubbers on Units 1 and 2 to reduce SO₂ emissions. The first planning period ended in 2018. NDWEE and the District provided comments opposing the proposed rule as arbitrary and capricious and contrary to the law and the facts. The EPA has not acted on the proposal.

On August 20, 2024, the NDWEE submitted the State Implementation Plan (“SIP”) for the second implementation period to the EPA. The SIP does not recommend any additional controls for the second implementation period (ending in 2028). The EPA is currently reviewing the SIP.

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 finalized a rule that tightened the PM emission limit and required coal-fired facilities to install PM Continuous Emission Monitoring Systems (“CEMS”) to continuously measure PM emissions. On June 17, 2025, the EPA proposed a rule that would repeal the requirements of the May 7, 2024 rule. On February 24, 2026, the EPA finalized the rule to repeal the requirements of the May 7, 2024 rule. The final rule reinstated the original PM emission limit and eliminated the requirement to continuously measure PM emissions with PM CEMS.

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 SO₂ 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 SO₂ at each facility pursuant to an allowance system. Based on current generation projections through 2032, the District expects to have sufficient Acid Rain allowances to cover affected facilities through 2032 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 SO₂ 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 2032, the District expects to have sufficient CSAPR allowances to cover affected facilities emission requirements through 2032 but may be required to purchase additional allowances in the future.

Waste – Coal Combustion Residuals (“CCR”) Legacy Rule

The NDWEE has issued permits to the District to establish and operate disposal areas for solid waste and ash at Sheldon Station and Gerald Gentleman Station. Additionally, the District’s ash landfills are regulated under the new CCR regulation.

The CCR rule was published in the Federal Register on April 17, 2015. The compliance requirements of the rule became effective on October 19, 2015. The final rule does not regulate CCR as a hazardous waste, instead it is regulated under Subtitle D. This resulted in relatively minor impacts on District operations to dispose of CCR due to the stringency of the current Nebraska solid waste landfill requirements. In 2015, the District completed a lateral expansion of the Gerald Gentleman Station ash landfill. A groundwater monitoring network was developed around the landfills. Periodic groundwater sampling is required to ensure compliance with the CCR regulations. The District is in compliance with the applicable requirements of the CCR regulations and the State Title 132 landfill requirements.

On May 8, 2024, the EPA finalized revisions to the CCR regulations. The new rule (“Legacy Rule”) is applicable to closed CCR landfills and CCR burial sites (“CCR Management Units”) that were closed prior to the 2015 CCR Rule. The rule requires an evaluation of any CCR that is buried onsite, a monitoring network to be installed around the burial sites, closure and post-closure care of the burial sites. The EPA is currently working on rule updates that would extend some of these deadlines. The District will continue to monitor the Legacy Rule.

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, 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 and USFWS both decided not to appeal the district court’s decision. The USFWS has commenced the process of addressing the court’s decision on remand, which involves, among other things, initiating the NEPA process for a supplement to the FEIS. Due to significant delays and difficulties encountered in the Section 106 consultation process, the District requested coverage under the Department of the Interior’s Emergency Process for Section 106 Compliance on August 22, 2025. The Department of the Interior approved that request on January 13, 2026, which initiated a seven-day Section 106 consultation period under the Emergency Process that concluded on January 20, 2026. The USFWS issued the Notice of Availability of the Final SEIS for the R-Project on January 30, 2026, and issued a Record of Decision and new Incidental Take Permit on February 10, 2026.

On March 3, 2026, various petitioners filed a petition for review in U.S. District Court for the District of Colorado against the USFWS and certain Department of Interior officials challenging USFWS’s approval of the ITP for the R-Project through the use of the Department of the Interior’s Emergency Process for National Historic Preservation Act Section 106 Compliance. Said petitioners have requested the court to vacate the ITP and enjoin USFWS’s further authorization of R-Project construction activities pending the completion of a renewed NHPA Section 106 process. On March 13, 2026, the District filed a motion to intervene. On March 25, 2026, the petitioners filed a motion for a preliminary injunction seeking to enjoin the USFWS, ACHP, and the District in order to preserve the status quo and prevent any construction pending a determination on the merits.

Before commencing construction, the District must apply for and receive approval from the Nebraska Public Service Commission pertaining to transmission line clearances over other utilities and certain other structures which was previously received but cancelled at the District’s request due to project delays.

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 January 2026 the District began decommissioning the Spencer Hydro Facility. The decommissioning project is estimated to cost approximately \$12.0 million and expected to be completed by late spring of 2026. The District anticipates most of the costs will be reimbursed through federal and state emergency management programs.

There is no remaining litigation relating to the flooding event. An inverse condemnation claim for downstream property damage resulted in a court order finding no liability for the District.

13. LITIGATION:

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

In addition to the litigation described herein, at the present time, the District is a named party in a variety of pending litigation cases common to utilities similar to the District. It is the opinion of management to the District, based on the advice of General Counsel to the District, that, when finally determined, the outcome of those cases will not likely result, either in the aggregate or individually, in a final judgment against the District, which would materially and adversely affect the financial position of the District.

14. SUBSEQUENT EVENTS:

Subsequent significant contracts-

Effective January 1, 2026, the District entered into new Wholesale Contracts that have a term that extends to 2060. See additional information in Note 12.C., *Retail Agreements and Wholesale Power Contracts*.

In January 2026, the District entered into a revolving credit agreement on January 29, 2026 with a commercial bank. The 2026 Revolving Credit Agreement provides for a loan commitment to the District up to an aggregate amount not to exceed \$100.0 million. The 2026 Revolving Credit Agreement terminates on October 15, 2027. As of March 31, 2026, no amounts were outstanding under the 2026 Revolving Credit Agreement.

In February 2026, the District entered into a contract for engineering, procurement, and construction services for a Reciprocating Internal Combustion Engine and Combustion Turbine generation facility at Princeton Road Station. The contract exceeds \$400.0 million. See additional information in the *Princeton Road Station* section of the Management's Discussion and Analysis.

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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)

	2025	2024	2023	2022	2021
Total OPEB Liability					
Service Cost	\$ 1,929	\$ 2,263	\$ 2,693	\$ 2,663	\$ 2,103
Interest	19,184	18,802	18,064	18,237	18,775
Changes of Benefit Terms	-	-	-	-	8,598
Differences between Expected and Actual Experiences	1,635	1,369	(7,325)	(7,054)	(20,995)
Changes of Assumptions	15,895	1,825	(8,939)	12,621	9,367
Benefit Payments, net of employee contributions	(17,714)	(17,927)	(16,867)	(15,710)	(14,026)
Net Change in Total OPEB Liability	20,929	6,332	(12,374)	10,757	3,822
Total OPEB Liability (Beginning)	313,736	307,404	319,778	309,021	305,199
Total OPEB Liability (Ending) (a)	<u>\$334,665</u>	<u>\$ 313,736</u>	<u>\$ 307,404</u>	<u>\$ 319,778</u>	<u>\$ 309,021</u>
Plan Fiduciary Net Position					
Contributions	\$ 2,406	\$ 2,850	\$ 6,294	\$ 28,283	\$ 28,283
Net Investment Income (Loss)	44,797	47,295	(65,647)	46,479	47,237
Benefit Payments, net of employee contributions	(17,714)	(17,927)	(16,867)	(15,710)	(14,026)
Administrative Expense	(255)	(231)	(212)	(259)	(205)
Net Change in Plan Fiduciary Net Position	29,234	31,987	(76,432)	58,793	61,289
Plan Fiduciary Net Position (Beginning)	357,897	325,910	402,342	343,549	282,260
Plan Fiduciary Net Position (Ending) (b)	<u>\$387,131</u>	<u>\$ 357,897</u>	<u>\$ 325,910</u>	<u>\$ 402,342</u>	<u>\$ 343,549</u>
Net OPEB (Asset) Liability (Ending) (a) - (b)	<u>\$ (52,466)</u>	<u>\$ (44,161)</u>	<u>\$ (18,506)</u>	<u>\$ (82,564)</u>	<u>\$ (34,528)</u>
Net Position as a % of Total OPEB Liability	115.7%	114.1%	106.0%	125.8%	111.2%
Covered-Employee Payroll	\$250,792	\$228,081	\$ 217,047	\$ 200,353	\$ 188,451
Net OPEB (Asset) Liability as a % of Covered-Employee Payroll .	<u>(20.9%)</u>	<u>(19.4%)</u>	<u>(8.5%)</u>	<u>(41.2%)</u>	<u>(18.3%)</u>

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

	2025	2024	2023	2022	2021
Actuarially Determined Contribution	\$ 2,035	\$ 2,050	\$ 2,404	\$ 2,847	\$ 2,871
Contributions Made in Relation to the Actuarially Determined Contribution	2,399	2,406	2,850	6,294	28,283
Contribution Deficiency (Excess)	<u>\$ (364)</u>	<u>\$ (356)</u>	<u>\$ (446)</u>	<u>\$ (3,447)</u>	<u>\$ (25,412)</u>
Covered-Employee Payroll	\$ 279,634	\$ 250,792	\$ 228,081	\$ 217,047	\$ 200,353
Contributions as a percentage of covered payroll	0.9%	1.0%	1.2%	2.9%	14.1%

Schedules of Investment Returns for Years Ended December 31,

	2025	2024	2023	2022	2021
Annual Money-Weighted Rate of Return, Net of Investment Expense	14.2%	12.8%	14.9%	(16.6%)	13.3%

Total OPEB Liability	2020	2019	2018	2017	2016
Service Cost	\$ 2,299	\$ 2,771	\$ 2,760	\$ 3,322	\$ 3,229
Interest	19,604	19,661	20,032	20,658	19,876
Changes of Benefit Terms	-	-	-	-	-
Differences between Expected and Actual Experiences	(19,961)	(8,686)	(19,570)	(203)	13,657
Changes of Assumptions	(1,608)	(751)	5,585	(18,807)	(9,149)
Benefit Payments, net of employee contributions	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Net Change in Total OPEB Liability	(12,473)	(1,065)	(6,607)	(8,489)	10,711
Total OPEB Liability (Beginning)	317,672	318,737	325,344	333,833	323,122
Total OPEB Liability (Ending) (a)	\$ 305,199	\$ 317,672	\$ 318,737	\$ 325,344	\$ 333,833

Plan Fiduciary Net Position

Contributions	\$ 41,084	\$ 56,706	\$ 28,439	\$ 74,711	\$ 28,242
Net Investment Income (Loss)	41,733	(6,892)	21,350	6,102	(453)
Benefit Payments, net of employee contributions	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Administrative Expense	(188)	(130)	(70)	(69)	(150)
Net Change in Plan Fiduciary Net Position	69,822	35,624	34,305	67,285	10,737
Plan Fiduciary Net Position (Beginning)	212,438	176,814	142,509	75,224	64,487
Plan Fiduciary Net Position (Ending) (b)	\$ 282,260	\$ 212,438	\$ 176,814	\$ 142,509	\$ 75,224

Net OPEB (Asset) Liability (Ending) (a) - (b)

	\$ 22,939	\$ 105,234	\$ 141,923	\$ 182,835	\$ 258,609
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Net Position as a % of Total OPEB Liability

	92.5%	66.9%	55.5%	43.8%	22.5%
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Covered-Employee Payroll

	\$ 182,154	\$ 178,815	\$ 171,774	\$ 182,197	\$ 170,317
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Net OPEB (Asset) Liability as a % of Covered-Employee Payroll .

	12.6%	58.9%	82.6%	100.4%	151.8%
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	2020	2019	2018	2017	2016
Actuarially Determined Contribution	\$ 6,676	\$ 12,967	\$ 18,572	\$ 21,006	\$ 28,283
Contributions Made in Relation to the Actuarially Determined Contribution	28,283	41,084	56,706	28,439	74,712
Contribution Deficiency (Excess)	\$ (21,607)	\$ (28,117)	\$ (38,134)	\$ (7,433)	\$ (46,429)
Covered-Employee Payroll	\$ 188,451	\$ 182,154	\$ 178,815	\$ 171,774	\$ 182,197
Contributions as a percentage of covered payroll	15.0%	22.6%	31.7%	16.6%	41.0%

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

NOTES TO REQUIRED SUPPLEMENTARY INFORMATION (UNAUDITED)

GASB guidance requiring this information was implemented by the District in 2016.

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 HRA.

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	8-year closed period for 2025, 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: 8.6% initial, ultimate 4.5% for 2025 Post-Medicare: 9.7% initial, ultimate 4.5% for 2025 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
HRA increase rate	3% for 2025 through 2021
Administrative cost trend	3.0%
Inflation	2.3% for 2025 and 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 2025 through 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 2025 through 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 2025 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 2025 and 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 2025 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)

	2025	2024
Operating revenues	\$ 1,154,555	\$ 1,163,637
Operating expenses	(1,125,179)	(1,155,493)
Operating income	29,376	8,144
Investment and other income (loss)	64,221	62,224
Debt and related expenses	(33,797)	(33,553)
Increase in net position	59,800	36,815
Add:		
Debt and related expenses ⁽¹⁾	33,797	33,553
Depreciation and amortization ⁽²⁾	122,225	125,572
Payments to retail communities ⁽³⁾	34,223	32,164
Amortization of current portion of financed nuclear fuel ⁽⁴⁾	37,176	-
	<u>227,421</u>	<u>191,289</u>
Deduct:		
Investment income (loss) retained in construction funds ⁽⁵⁾	(239)	690
Unrealized gain (loss) on investment securities	1,634	(1,161)
	<u>1,395</u>	<u>(471)</u>
Net revenues available for debt service under the General System Bond Resolution	<u>\$ 285,826</u>	<u>\$ 228,575</u>
General system bonded debt service ⁽⁶⁾	109,981	100,034
Ratio of net revenues available for debt service ⁽⁶⁾	2.60	2.28

- (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 2025 than 2024 due primarily to an increase in net revenues available for debt service (also referred to as debt service coverage). The 2025 ratio of net revenues available for debt service was higher due to lower operating expenses and the amortization of the current portion of financed nuclear fuel. The debt service coverage was higher in 2024 than 2023 due primarily to a decrease in General System Bonded Debt Service.



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