

OTTER TAIL POWER COMPANY
NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Overview

Otter Tail Power Company ("OTP", the "Company", "us", "our" or "we"), a wholly owned subsidiary of Otter Tail Corporation with headquarters in Fergus Falls, Minnesota, is a vertically integrated, regulated utility with generation, transmission and distribution facilities to provide electricity to approximately 134,000 customers in a service area encompassing approximately 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. Our service territory is predominantly rural and agricultural and includes over 400 communities, most of which have populations of less than 10,000.

In addition to earning retail revenue, we are also a participant in the Midcontinent Independent System Operator, Inc. (MISO) markets allowing us to transmit electricity for others over the transmission assets we wholly or jointly own and to sell electricity we generate into the wholesale electricity market.

Use of Estimates

We use estimates based on the best information available in recording transactions and balances resulting from business operations. As better information becomes available or actual amounts are known, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Regulatory Accounting

We are subject to regulation of rates and other matters by state utility commissions in Minnesota, North Dakota and South Dakota and by the Federal Energy Regulatory Commission (FERC) for certain interstate operations. We account for the financial effects of regulation in accordance with accounting guidance for regulated operations. This guidance allows for the recording of a regulatory asset for certain costs which otherwise would be recognized in the statements of comprehensive income based on an expectation that the cost will be recovered in future rates. This guidance also requires the recording of a regulatory liability for certain credits which would otherwise be recognized in the statements of comprehensive income based on an expectation that the amount will be returned to customers in future rates. Amounts recorded as regulatory assets and regulatory liabilities are generally recognized in the statements of comprehensive income at the time they are reflected in customer rates. In the event we cease to meet the criteria to apply the guidance for regulated operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the balance sheets and included in the statements of comprehensive income as an expense, income, gain or loss item in the period in which the application of this guidance ceases.

Cash Equivalents

We consider all highly liquid investments purchased with maturities of 90 days or less to be cash equivalents.

Revenue from Contracts with Customers

We recognize revenue from contracts with customers at prices that are fixed or determinable as evidenced by an agreement with the customer, when we have met our performance obligation under the contract and it is probable that we will collect the amount to which we are entitled in exchange for the goods or services transferred or to be transferred to the customer. We recognize revenue over time for the delivery or transmission of electricity or related services. Sales or other taxes collected from customers are excluded from operating revenues.

Most revenues are earned from the generation, transmission and sale of electricity to retail customers at rates approved by state regulatory commissions. We also earn revenue from the transmission of electricity for others over the transmission assets we own separately or jointly with other transmission service providers, under rate tariffs established by the independent transmission system operator and approved by FERC. A third source of revenue comes from the generation and sale of electricity to wholesale customers at contract or market rates. Revenues from all these sources meet the criteria to be classified as revenue from contracts with customers and are recognized over time as energy is delivered or transmitted. Revenue is recognized based on the metered quantity of electricity delivered or transmitted at the applicable rates. For electricity delivered and consumed after a meter is read but not yet billed to a customer, we record revenue and an unbilled receivable based on estimates of the amount of energy delivered and a composite rate per kwh consumed.

Alternative Revenue

In addition to recognizing revenue from contracts with customers, we also record revenue under alternative revenue program (ARP) requirements. Certain rate rider mechanisms qualify as ARP revenues as they provide for adjustments to rates outside of a general rate case proceeding to encourage or incentivize investments in certain areas such as conservation, renewable energy, pollution reduction or control, improved infrastructure of the transmission grid or other programs that provide benefits to the general public

under public policy, laws or regulations. ARP riders generally provide for the recovery of specified costs and investments and include an incentive component to provide the regulated utility with a return on amounts invested.

We accrue ARP revenue on the basis of costs incurred, investments made and returns on those investments that qualify for recovery through established riders. ARP revenue is disclosed separately from revenue from contracts with customers and we have elected to report ARP revenue on a net basis, whereby amounts initially recorded as ARP revenue in a period are presented net of the reversal of amounts previously recognized as ARP revenue that are reclassified and recorded as revenue from contracts with customers when such amounts are included in the price of electricity to customers.

Receivables and Allowance for Credit Losses

We grant credit to our customers in the normal course of business with repayment terms generally 30 days after the invoice date. Late fees are assessed on certain receivables once they are 30 days past due. Unbilled receivables represent estimates of energy delivered to customers but not yet billed.

Receivables are stated at the billed or estimated unbilled amount less an allowance for estimated credit losses. An allowance for credit losses is established based on losses expected to occur over the contractual life of the receivable. We estimate an allowance for credit losses on our trade and unbilled receivables by evaluating historical aging and write-off history, adjusted for current and forecasted economic conditions, for groups of receivables that share similar economic characteristics. Other receivables are evaluated by reviewing individual accounts, considering aging, financial condition of the debtor, recent payment history and other relevant factors. Account balances are written off in the period they are deemed to be uncollectible.

Inventories

Inventories are valued at the lower of cost or net realizable value. Costs for fuel, material and supply inventories are determined on an average cost basis.

Property, Plant and Equipment

Electric plant is stated at original cost less accumulated depreciation. The cost of additions includes purchased assets, contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized to electric plant was \$1.9 million in 2024 and \$1.9 million in 2023. Significant additions or improvements that extend an asset's useful life are capitalized, while repairs and maintenance costs are expensed as incurred.

Depreciation is recognized on a straight-line basis over the asset's estimated useful life. For certain asset classes, we employ a group or composite method of depreciation in which certain assets are combined and depreciated over the average life of the combined asset group. Actuarial studies are periodically performed to assess the remaining useful lives and salvage values of our assets, with any changes in these estimates incorporated into depreciation on a prospective basis. Gains or losses on group or composite asset dispositions are recorded to accumulated depreciation and impact current and future depreciation rates.

Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Removal costs, when incurred, are charged against the regulatory liability.

The estimated service lives for rate-regulated electric assets are included below:

(years)	Service Life Range	
	Low	High
Electric Assets:		
Production Plant	21	114
Transmission Plant	51	80
Distribution Plant	10	72
General Plant	5	56

Jointly Owned Facilities

We are a joint owner in two coal-fired steam-powered electric generation plants: Big Stone Plant near Big Stone City, South Dakota and Coyote Station near Beulah, North Dakota. We are also a joint owner, with other regional utilities, in several major transmission lines. Our interest in each jointly owned facility is reflected in the balance sheets on a pro-rata basis and our share of direct revenue and expenses are included in operating revenues and expenses in the statements of comprehensive income. Each participant in the jointly owned facilities finances their own investments.

Cloud Computing Costs

We capitalize implementation costs incurred in cloud computing arrangements that are service contracts consistent with capitalized implementation costs incurred to develop or obtain internal-use software. Costs are amortized on a straight-line basis over the life of the associated contract. Capitalized implementation costs are amortized over periods up to ten years. Capitalized costs and related

accumulated amortization are included in other noncurrent assets on our balance sheets. Below are the amounts of capitalized cost and related accumulated amortization as of December 31, 2024 and 2023:

<i>(in thousands)</i>	2024		2023	
Cloud Computing Costs	\$	14,609	\$	11,812
Accumulated Amortization		(3,476)		(1,399)
Cloud Computing Costs, net	\$	11,133	\$	10,413

Amortization expense of capitalized implementation costs for each of the years ended December 31, 2024 and 2023 totaled \$2.1 million and \$0.6 million.

Leases

We recognize a right-of-use lease asset and a corresponding lease liability at the lease commencement date. The length of our lease agreements varies from less than one year to approximately five years. We have elected to not record lease assets and liabilities for leases with a lease term at commencement of 12 months or less; such leases are expensed on a straight-line basis over the lease term. If a lease contains an option to extend the lease term and there is reasonable certainty the option will be exercised, the option is considered in the lease term at inception. We have elected to not separate non-lease components (e.g., common area maintenance) from lease components on real estate leases, accordingly the recognized lease asset and lease liability incorporate in their measurement payments for non-lease components. We are unable to determine the interest rate implicit in our leases thus we apply our incremental borrowing rate to capitalize the right-of-use asset and lease liability. We estimate our incremental borrowing rate by incorporating considerations of lease term and our credit metrics.

Recoverability of Long-Lived Assets

We review our long-lived assets including, among other assets, property, plant and equipment, capitalized cloud computing costs and right-of-use lease assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. We determine potential impairment by comparing the carrying amount of the assets with the net cash flows expected to be provided by operating activities of the business or related assets. If the sum of the expected future net cash flows is less than the carrying amount of the assets, an impairment loss would be recognized. Such an impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset.

Pension Plans and Other Benefits

Current and retired employees of OTP participate in a funded pension plan, an unfunded supplemental pension plan, a postretirement healthcare plan and certain nonqualified deferred compensation plans sponsored by Otter Tail Corporation. We have elected to recognize our estimated proportionate share of the assets, where applicable, and liabilities of these plans in our balance sheets, and to recognize the allocated share of the cost of these plans in our statements of comprehensive income. Generally, the allocation to recognize our proportionate share of assets, liabilities and cost of the plans is based on relative headcount of employees participating in each respective plan.

Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates. Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

We have elected to apply a minimum amortization method for determining the amount of amortization of net cumulative gains or losses to be included as a component of net periodic benefit cost for any annual period. Cumulative gains and losses recognized in accumulated other comprehensive income or as a deferred regulatory asset or liability that are in excess of 10% of the projected benefit obligation or the market value of pension plan assets are amortized over the expected remaining future service period of active plan participants. In periods in which the cumulative gains and losses do not exceed 10%, no amortization to net period benefit cost is recognized.

Asset Retirement Obligations

Legal obligations related to the future retirement of long-lived assets are recognized as asset retirement obligations (ARO). An ARO is recognized in the period in which the legal obligation is incurred, and the amount of the obligation can be reasonably estimated, with an offsetting increase to the associated long-lived asset. AROs are initially recognized at fair value and increased with the passage of time (accretion). ARO estimates are revised periodically with any adjustments reflected in the ARO and associated long-lived asset.

Income Taxes

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns. We have elected to use a modified separate return method to record income taxes in these financial statements. Under this method, we recognize current and deferred tax expense and tax assets and liabilities as if we filed separate income tax returns. We modify the separate return method only in our assessment of the realizability of our deferred tax assets, in which we assess realizability based on future sources of taxable income of Otter Tail Corporation and its subsidiaries.

We use the asset and liability method to account for income taxes. Under this method, deferred tax assets and liabilities are recognized for the expected future tax consequences of all temporary differences between the carrying amounts of assets and liabilities and their respective tax bases. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. Deferred tax assets are reduced by a valuation allowance when it is more likely than not that a portion or all of the deferred tax assets will not be realized by Otter Tail Corporation and its subsidiaries. The realizability of deferred tax assets is determined by taking into consideration for Otter Tail Corporation and its subsidiaries forecasts of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies. Changes in valuation allowances are included in the provision for income taxes in the period of the changes.

We recognize the tax effects of all tax positions that are more-likely-than-not to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. Changes in the recognition or measurement of such positions are recognized in the provision for income taxes in the period of the changes. We classify interest and penalties on tax uncertainties as components of the provision for income taxes.

We have elected to account for transferable tax credits as a component of our income tax provision. We recognize the benefit of PTCs as a reduction of income tax expense in the period the credit is generated, which corresponds to the period the energy production occurs. We apply the deferral method of accounting for ITCs and state wind energy credits. Under this method, ITCs and state wind energy credits are amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

Deferred Compensation Plans

Otter Tail Corporation sponsors two nonqualified deferred compensation plans for the benefit of executive officers and other select employees, including certain OTP officers and employees. Each plan allows participants to defer a specified amount or percentage of base wages or incentive compensation into the plan, subject to certain limitations. OTP, at its discretion, may make employer contributions to either plan during any annual period. Participant and employer deferred amounts are segregated into one or more accounts chosen by the participant. Participants earn a return on deferred amounts based on notional investments in the segregated accounts. Participants can elect lump sum distributions or annual installments of deferred balances during the participant's employment or upon retirement. As of December 31, 2024 and 2023, our liability to participants under these deferred compensation plans was \$3.7 million and \$3.0 million. OTP contributions to these plans were \$0.3 million for each of the years ended December 31, 2024 and 2023. Losses recognized due to changes in our payment obligations in connection with these plans amounted to \$0.3 million for each of the years ended December 31, 2024 and 2023.

Fair Value Measurements

Fair value is defined as the price that would be received for 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. Three levels of inputs may be used to measure fair value:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed on the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

In instances where the determination of the fair value measurement is based on inputs from different levels within the hierarchy, the level in the hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety.

Variable Interest Entity

In October 2012, the Coyote Station owners, including OTP, entered into a lignite service agreement (LSA) with Coyote Creek Mining Company, LLC (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of lignite coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed upon profit and capital charge. CCMC was formed for the purpose of mining coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are required to buy certain assets of CCMC at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC because the Coyote Station owners are required to buy the membership interests of CCMC at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE and we are not required to include CCMC in our financial statements.

If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC, the owners will satisfy or, if permitted by CCMC's applicable lenders, assume all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. In the event the contract is terminated prior to the end of the term due to certain events, our maximum loss exposure, as a result of our involvement with CCMC, could be as high as \$40 million, our 35% share of CCMC's unrecovered costs as of December 31, 2024, if recovery of such a loss is denied by regulatory authorities.

Recent Accounting Pronouncements

Income Taxes. In December 2023, the FASB issued amended authoritative guidance codified in ASC 740, Income Taxes. The amended guidance requires additional disaggregated information in effective tax rate reconciliation disclosures and additional disaggregated information about income taxes paid. The updated standard is effective for our annual periods beginning in 2026, and early adoption is permitted. The amended guidance is to be applied on a prospective basis with the option to apply the standard retrospectively. We anticipate adopting the updated standard in our financial statements for the year ended December 31, 2025 and electing to apply the standard on a retrospective basis for all periods presented.

Subsequent Events

We evaluated subsequent events through March 7, 2025, the date these financial statements were available to be issued and did not identify any events requiring recognition or disclosure in these financial statements, except as disclosed in note 16.

2. Revenue

The following presents our operating revenues from external customers, in total and by amounts arising from contracts with customers and ARP arrangements, disaggregated by revenue source for the years ended December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Operating Revenues		
Retail: Residential	\$ 133,408	\$ 135,570
Retail: Commercial and Industrial	311,968	312,551
Retail: Other	7,838	7,719
Total Retail	453,214	455,840
Transmission	53,517	52,555
Wholesale	11,077	12,459
Other	6,707	7,505
Total Operating Revenues	524,515	528,359
ARP Revenues	575	(4,310)
Total Operating Revenues from Contracts with Customers	\$ 523,940	\$ 532,669

Concentration

While our customer base includes relatively few large customers, sales to commercial and industrial customers are significant, with a single customer accounting for 13% and 12% of total operating revenues for the years ended December 31, 2024 and 2023.

3. Receivables

Receivables and Allowance for Credit Losses

Receivables as of December 31, 2024 and 2023 are as follows:

<i>(in thousands)</i>	2024		2023	
Receivables				
Trade	\$	20,769	\$	22,301
Other		13,227		8,385
Unbilled Receivables		21,916		21,324
Total Receivables		55,912		52,010
Less Allowance for Credit Losses		1,550		1,548
Receivables, net of allowance for credit losses	\$	54,362	\$	50,462

The following is a summary of activity in the allowance for credit losses for the years ended December 31, 2024 and 2023:

<i>(in thousands)</i>	2024		2023	
Beginning Balance, January 1	\$	1,548	\$	1,310
Additions Charged to Expense		1,280		1,376
Reductions for Amounts Written Off, Net of Recoveries		(1,278)		(1,138)
Ending Balance, December 31	\$	1,550	\$	1,548

4. Regulatory Matters

Regulatory Assets and Liabilities

The following presents our current and long-term regulatory assets and liabilities as of December 31, 2024 and 2023 and the period we expect to recover or refund such amounts:

(in thousands)	Period of Recovery/Refund	2024		2023	
		Current	Long-Term	Current	Long-Term
Regulatory Assets					
Pension and Other Postretirement Benefit Plans ¹	See below	\$ —	\$ 88,161	\$ 154	\$ 86,134
Alternative Revenue Program Riders ²	Up to 2 years	4,257	195	3,719	158
Deferred Income Taxes	Asset lives	—	8,944	—	6,940
Fuel Clause Adjustments ¹	Up to 1 year	2,218	—	7,294	—
Derivative Instruments ¹	Up to 1 year	1,989	—	4,210	—
Other ¹	Various	1,498	1,373	750	2,483
Total Regulatory Assets		\$ 9,962	\$ 98,673	\$ 16,127	\$ 95,715
Regulatory Liabilities					
Deferred Income Taxes	Asset lives	\$ —	\$ 130,387	\$ —	\$ 136,022
Plant Removal Obligations	Asset lives	—	126,263	—	117,030
Fuel Clause Adjustments	Up to 1 year	11,432	—	11,350	—
Alternative Revenue Program Riders	Up to 1 year	14,255	—	6,885	—
North Dakota PTC Refunds	Asset lives	—	20,099	—	12,011
Pension and Other Postretirement Benefit Plans	See below	2,547	10,758	6,138	11,307
Other	Various	1,073	1,421	1,035	177
Total Regulatory Liabilities		\$ 29,307	\$ 288,928	\$ 25,408	\$ 276,547

¹Costs subject to recovery without a rate of return.

²Amount eligible for recovery includes an incentive or rate of return.

Pension and Other Postretirement Benefit Plans represent benefit costs and actuarial losses and gains subject to recovery or refund through rates as they are expensed or amortized. These unrecognized benefit costs and actuarial losses and gains are eligible for treatment as regulatory assets or liabilities based on their probable inclusion in future electric rates.

Alternative Revenue Program Riders regulatory assets and liabilities are revenues not yet collected from customers or amounts collected from customers that are subject to refund, respectively, primarily due to investments in qualifying transmission,

conservation, renewable resource, environmental and other generation assets, and the impact of decoupling.

Deferred Income Taxes represent the revaluation of accumulated deferred income taxes arising from the change in the federal income tax rate in 2017. This amount is being refunded to customers over the estimated lives of the property assets from which the deferred income taxes originated.

Fuel Clause Adjustments represent the under- or over-collection of fuel costs relative to the estimated cost of fuel included in customer rates, which will be collected from or returned to customers in future periods.

Derivative Instruments represent unrealized losses recognized on derivative instruments. On final settlement of such instruments, any realized losses are recovered from customers.

Plant Removal Obligations represent amounts collected from customers to be used to cover actual removal costs as incurred.

North Dakota PTC Refunds represent PTCs earned from our wind energy facilities. These amounts are being allocated to customers over the life of the assets generating the credits.

Other regulatory assets and liabilities include other amounts that we expect to recover from, or return to, customers in future periods, such as the cost of abandoned projects, costs incurred in connection with recent rate cases and other items.

North Dakota Rate Case

On November 2, 2023, we filed a request with the North Dakota Public Service Commission (NDPSC) for an increase in revenue recoverable under general rates in North Dakota. In our filing, we requested a net increase in annual revenue of \$17.4 million, or 8.4%, based on an allowed rate of return on rate base of 7.85% and an allowed rate of return on equity of 10.6% on an equity ratio of 53.5% of total capital. The filing also included an interim rate request of a net increase in annual revenue of \$12.4 million, or 6.0%, which was approved by the NDPSC on December 13, 2023. Interim rates went into effect on January 1, 2024. On July 3, 2024, we filed an update to our original request increasing the amount of the net annual revenue requirement from \$17.4 million to \$22.5 million, or a net increase of 10.9% in annual revenue, to account for certain items identified throughout the regulatory process.

On December 30, 2024, the NDPSC approved a settlement agreement between OTP and certain interested parties in the general rate case and issued its written order on final rates. The key provisions of the order include a revenue requirement of \$225.6 million, based on a return on rate base of 7.53%, and an allowed ROE of 10.10% on an equity ratio of 53.5%. The net annual revenue requirement includes a net increase of \$13.1 million, or 6.18%. Our revenue requirement was reduced by approximately \$3.0 million primarily due to the inclusion of forecasted PTCs plus adjustments for new customer load additions, which were not included in our updated request filed on July 3, 2024. Through the settlement of the case, the parties also agreed to establish an earnings sharing mechanism, whereby 70% of actual earnings in excess of a 10.20% ROE would be returned to customers, with OTP retaining the remaining 30%.

5. Electric Plant

Major classes of electric plant as of December 31, 2024 and 2023 included:

<i>(in thousands)</i>	<i>2024</i>	<i>2023</i>
Electric Plant in Service		
Production	\$ 1,469,008	\$ 1,412,826
Transmission	820,415	777,613
Distribution	726,159	654,704
General	165,361	144,738
Electric Plant in Service	3,180,943	2,989,881
Construction Work in Progress	231,890	137,212
Other Property - Land	195	216
Total Gross Electric Plant	3,413,028	3,127,309
Less Accumulated Depreciation and Amortization	899,049	851,147
Net Electric Plant	\$ 2,513,979	\$ 2,276,162

Depreciation expense for the years ended December 31, 2024 and 2023 totaled \$78.6 million and \$72.3 million.

The following table provides our ownership percentages and amounts included in the December 31, 2024 and 2023 balance sheets for our share of each of these jointly owned facilities:

<i>(dollars in thousands)</i>	<i>Ownership Percentage</i>	<i>Electric Plant in Service</i>	<i>Construction Work in Progress</i>	<i>Accumulated Depreciation</i>	<i>Net Plant</i>
December 31, 2024					
Big Stone Plant	53.9 %	\$ 345,990	\$ 459	\$ (135,065)	\$ 211,384
Coyote Station	35.0 %	188,066	813	(118,268)	70,611
Big Stone South–Ellendale 345 kV line	50.0 %	106,185	—	(8,445)	97,740
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(12,247)	65,937
Big Stone South–Brookings 345 kV line	50.0 %	53,167	—	(5,822)	47,345
Brookings–Southeast Twin Cities 345 kV line	4.8 %	28,013	1,131	(3,941)	25,203
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(3,693)	12,638
Jamestown– Ellendale 345 kV line	50.0 %	—	5,509	—	5,509
Big Stone South–Alexandria 345 kV line	40.0 %	—	2,418	—	2,418
Alexandria–Big Oaks 345 kV line	14.2 %	—	417	—	417
Oslo - Lake Ardoch 115 kV line	72.0 %	—	2,646	—	2,646
December 31, 2023					
Big Stone Plant	53.9 %	\$ 341,683	\$ 820	\$ (126,904)	\$ 215,599
Coyote Station	35.0 %	188,656	104	(115,306)	73,454
Big Stone South–Ellendale 345 kV line	50.0 %	106,185	—	(7,181)	99,004
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(11,238)	66,946
Big Stone South–Brookings 345 kV line	50.0 %	53,170	—	(5,207)	47,963
Brookings–Southeast Twin Cities 345 kV line	4.8 %	26,409	83	(3,617)	22,875
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(3,568)	12,763
Jamestown– Ellendale 345 kV line	50.0 %	—	1,121	—	1,121
Big Stone South–Alexandria 345 kV line	40.0 %	—	555	—	555
Alexandria–Big Oaks 345 kV line	14.2 %	—	343	—	343

6. Leases

We lease rail cars, office space, and certain operating and construction equipment under varying terms and conditions. All leases are classified as operating leases.

The components of lease cost and lease cash flows for the years ended December 31, 2024 and 2023 are as follows:

<i>(in thousands)</i>	2024	2023
Lease Cost		
Operating Lease Cost	\$ 1,192	\$ 1,175
Short-Term Lease Cost	1,288	1,368
Total Lease Cost	\$ 2,480	\$ 2,543
Lease Cash Flows		
Operating Cash Flows from Operating Leases	\$ 1,064	\$ 1,189

A summary of operating lease right-of-use lease assets and lease liabilities as of December 31, 2024 and 2023 are as follows:

<i>(in thousands)</i>	2024	2023
Right-of-Use Lease Assets ¹	\$ 2,687	\$ 3,337
Lease Liabilities		
Current ²	1,030	1,134
Long-Term ³	1,679	2,299
Total Lease Liabilities	\$ 2,709	\$ 3,433

¹Included in Other Noncurrent Assets in the balance sheets.

²Included in Other Current Liabilities in the balance sheets.

³Included in Other Noncurrent Liabilities in the balance sheets.

Operating lease assets obtained in exchange for new operating lease liabilities amounted to \$0.8 million and \$0.2 million for the years ended December 31, 2024 and 2023.

Maturities of lease liabilities as of December 31, 2024 for each of the next five years and in the aggregate thereafter are as follows:

<i>(in thousands)</i>	Operating Leases
2025	\$ 1,109
2026	945
2027	497
2028	165
2029	151
Thereafter	—
Total Lease Payments	2,867
Less: Interest	158
Present Value of Lease Liabilities	\$ 2,709

The weighted-average remaining lease term and the weighted-average discount rate as of December 31, 2024 and 2023 are as follows:

	2024	2023
Weighted-Average Remaining Lease Term (in years)	3.0	3.0
Weighted-Average Discount Rate	3.69 %	3.14 %

7. Short-Term and Long-Term Borrowings

The following is a summary of our outstanding short- and long-term borrowings as of December 31, 2024 and 2023.

Short-Term Debt

The following is a summary of our line of credit as of December 31, 2024 and 2023:

<i>(in thousands)</i>	<i>Borrowing Limit</i>	<i>2024</i>			<i>2023</i>	
		<i>Amount Outstanding</i>	<i>Letters of Credit</i>	<i>Amount Available</i>	<i>Amount Available</i>	
Line of Credit	\$ 220,000	\$ 69,615	\$ 8,772	\$ 141,613	\$ 79,446	

On December 11, 2024, OTP entered into a Fifth Amended and Restated Credit Agreement, amending and restating the previously existing credit agreement to extend the maturity date of the credit facility and adjust the maximum debt to total capitalization covenant. The credit agreement was also amended to increase the maximum borrowing capacity. The OTP agreement provides for a \$220.0 million unsecured revolving line of credit to support operations, fund capital expenditures, refinance certain indebtedness and provide for the issuance of letters of credit in an aggregate amount not to exceed \$50.0 million. The credit facility includes an accordion provision allowing us to increase the borrowing capacity under the facility, subject to certain conditions, up to \$300.0 million.

Borrowings under the credit facility are subject to a variable rate of interest on outstanding balances and a commitment fee is charged based on the average unused amount available to be drawn under the facility. The variable rate of interest to be charged is based on a benchmark interest rate, either SOFR or a Base Rate, as defined in the credit agreement, selected by us at the time of an advance, subject to the conditions of the agreement, plus an applicable credit spread. The credit spread ranges from zero to 1.50%, depending on the benchmark interest rate selected, and is subject to adjustment based on our credit ratings. The weighted-average interest rate on our borrowings as of December 31, 2024 and 2023 was 5.61% and 6.70%.

The credit facility contains a number of restrictions on us, including restrictions on the ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The agreement also requires us to maintain various financial covenants, as further described below. The credit facility includes a cross-default provision whereby an event of default of other outstanding indebtedness will trigger an event of default under this agreement. The credit facility expires on December 11, 2029.

Long-Term Debt

The following is a summary of outstanding long-term debt as of December 31, 2024 and 2023:

<i>Debt Instrument</i>	<i>Rate</i>	<i>Maturity</i>	<i>(in thousands)</i>	
			<i>2024</i>	<i>2023</i>
Series 2007C Senior Unsecured Notes	6.37 %	08/02/27	\$ 42,000	\$ 42,000
Series 2013A Senior Unsecured Notes	4.68 %	02/27/29	60,000	60,000
Series 2019A Senior Unsecured Notes	3.07 %	10/10/29	10,000	10,000
Series 2020A Senior Unsecured Notes	3.22 %	02/25/30	10,000	10,000
Series 2020B Senior Unsecured Notes	3.22 %	08/20/30	40,000	40,000
Series 2021A Senior Unsecured Notes	2.74 %	11/29/31	40,000	40,000
Series 2024A Senior Unsecured Notes	5.48 %	04/01/34	60,000	—
Series 2007D Senior Unsecured Notes	6.47 %	08/20/37	50,000	50,000
Series 2019B Senior Unsecured Notes	3.52 %	10/10/39	26,000	26,000
Series 2020C Senior Unsecured Notes	3.62 %	02/25/40	10,000	10,000
Series 2013B Senior Unsecured Notes	5.47 %	02/27/44	90,000	90,000
Series 2018A Senior Unsecured Notes	4.07 %	02/07/48	100,000	100,000
Series 2019C Senior Unsecured Notes	3.82 %	10/10/49	64,000	64,000
Series 2020D Senior Unsecured Notes	3.92 %	02/25/50	15,000	15,000
Series 2021B Senior Unsecured Notes	3.69 %	11/29/51	100,000	100,000
Series 2022A Senior Unsecured Notes	3.77 %	05/20/52	90,000	90,000
Series 2024B Senior Unsecured Notes	5.77 %	04/01/54	60,000	—
Total			867,000	747,000
Less: Unamortized Long-Term Debt Issuance Costs			3,166	2,790
Total Long-Term Debt Net of Unamortized Debt Issuance Costs			\$ 863,834	\$ 744,210

On March 28, 2024, we entered into a Note Purchase Agreement pursuant to which we issued, in a private placement transaction, \$120.0 million of senior unsecured notes consisting of (a) \$60.0 million of 5.48% Series 2024A Senior Unsecured Notes due April 1, 2034, and (b) \$60.0 million of 5.77% Series 2024B Senior Unsecured Notes due April 1, 2054.

Per the terms of the agreement, we may prepay all or any part of the notes (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount, as defined in the agreement; provided that no default or event of default exists under the agreement. Any prepayment of the Series 2024A Notes then outstanding on or after January 1, 2034, or the Series 2024B Notes then outstanding on or after October 1, 2053, will be made without any make-whole amount. Consistent with other of our borrowings, the agreement contains a number of restrictions on our business, including restrictions on our ability to merge, sell substantially all assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in certain transactions with affiliates.

Our unsecured notes require us to maintain various financial covenants, as further described below. These notes provide for prepayment options allowing for a full or partial prepayment at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount, as defined. These notes also include restrictions on us, including our ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The notes include a cross-default provision whereby an event of default of other outstanding indebtedness will trigger an event of default under the note.

Maturities of long-term debt obligations as of December 31, 2024 for each of the next five years are as follows:

<i>(in thousands)</i>	<i>2025</i>		<i>2026</i>		<i>2027</i>		<i>2028</i>		<i>2029</i>
Debt Maturities	\$	—	\$	—	\$	42,000	\$	—	\$ 70,000

Financial Covenants

Certain of our short- and long-term debt agreements require us to maintain certain financial covenants, including a maximum debt to total capitalization of either 0.60 to 1.00 or 0.65 to 1.00, depending on the debt agreement, a minimum interest and dividend coverage ratio of 1.50 to 1.00, and a maximum level of priority indebtedness. As of December 31, 2024, we were in compliance with these financial covenants.

8. Employee Postretirement Benefits

Certain of our employees participate in benefit plans sponsored by Otter Tail Corporation, including a noncontributory funded pension plan (the Pension Plan), an unfunded, nonqualified Executive Survivor and Supplemental Retirement Plan (the ESSRP), both accounted for as defined benefit pension plans, and a postretirement healthcare plan accounted for as an other postretirement benefit plan.

The Pension Plan, which previously covered substantially all OTP employees, was closed to new employees in 2013. The plan provides retirement compensation to all covered employees at age 65, with reduced compensation in cases of retirement prior to age 62. Participants are fully vested after completing five years of vesting service. The plan assets consist of equity funds, fixed income funds, cash and cash equivalents and alternative investments. None of the plan assets are invested in common stock or debt securities of OTP or Otter Tail Corporation.

The ESSRP, an unfunded plan, provides for defined benefit payments to executive officers and certain key management employees on their retirement for life, or to their beneficiaries on their death. The ESSRP was amended and restated in 2019 to i) freeze the participation in the restoration retirement benefit component of the plan and ii) freeze benefit accruals under the restoration retirement benefit component of the plan for all participants of the plan except any participants deemed to be grandfathered participants.

The postretirement healthcare plan, closed to new participants in 2010, provides a portion of health insurance benefits for retired and covered OTP employees. To be eligible for retiree health insurance benefits, the employee must be 55 years of age with a minimum of 10 years of service. The plan is an unfunded plan and accordingly holds no plan assets.

Pension Plan Assets. Otter Tail Corporation has established a Retirement Plans Administration Committee to develop and monitor our investment strategy for our Pension Plan assets. The investment strategy includes the following objectives:

- The assets of the plan will be invested in accordance with all applicable laws in a manner consistent with fiduciary standards including Employee Retirement Income Security Act standards of 1974 (ERISA) (if applicable). Specifically:
 - The safeguards and diversity that a prudent investor would adhere to must be present in the investment program.
 - All transactions undertaken on behalf of the Pension Plan must be in the best interest of plan participants and their beneficiaries.
- The primary objective is to provide a source of retirement income for its participants and beneficiaries.
- The near-term primary financial objective is to improve and protect the funded status of the plan.
- A secondary financial objective is to minimize pension funding and expense volatility where possible.

We have developed an asset allocation target, measured at investment market value, to provide guideline percentages of investment mix. This investment mix is intended to achieve the financial objectives of the plan. The permitted range is a guide and will at times not reflect the actual asset allocation due to market conditions, actions of our investment managers and required cash flows to and from the Pension Plan.

The following table presents our target asset allocation permitted range along with the actual asset allocation as of December 31, 2024 and 2023:

<i>Asset Class</i>	Permitted Range	Actual Allocation	
		2024	2023
Return Enhancement	35 – 60%	41 %	48 %
Risk Management	40 – 80%	59	51
Alternatives	0 – 20%	—	1
Total		100 %	100 %

Return Enhancement investments are those that seek to provide equity-like, long-term capital appreciation. Examples include equity securities, including dynamic asset allocation funds, and higher yielding fixed income securities, such as high yield bonds and emerging market debt.

Risk Management investments seek to decrease downside risk or act as a hedge against plan liabilities. Examples are cash and fixed income instruments.

Alternative investments seek to either provide return enhancement through long-term appreciation or risk management through decreased downside risk. The defining characteristic of these asset types is uncorrelated source of returns, less liquidity and private market access. Examples include investments in the SEI Energy Debt Collective Fund.

The following presents the fair value inputs classified within the fair value hierarchy used to measure Pension Plan assets at December 31, 2024 and 2023 and assets measured using the net asset value (NAV) practical expedient:

<i>(in thousands)</i>	<i>Level 1</i>	<i>Level 2</i>	<i>Level 3</i>	<i>NAV</i>	<i>Total</i>
December 31, 2024					
Equity Funds	\$ 113,733	\$ —	\$ —	\$ —	\$ 113,733
Fixed Income Funds	170,577	—	—	—	170,577
Hybrid Funds	9,833	—	—	—	9,833
U.S. Treasury Securities	23,264	—	—	—	23,264
SEI Energy Debt Collective Fund	—	—	—	1,032	1,032
Total	317,407	—	—	1,032	318,439
December 31, 2023					
Equity Funds	123,854	—	—	—	123,854
Fixed Income Funds	163,246	—	—	—	163,246
Hybrid Funds	10,694	—	—	—	10,694
U.S. Treasury Securities	22,615	—	—	—	22,615
SEI Energy Debt Collective Fund	—	—	—	1,478	1,478
Total	\$ 320,409	\$ —	\$ —	\$ 1,478	\$ 321,887

The investments held by the SEI Energy Debt Collective Fund on December 31, 2024 and 2023 consist mainly of below investment grade high yield bonds and loans of U.S. energy companies which trade at a discount to fair value. Redemptions are allowed semi-annually with a 95-day notice period, subject to fund director consent and certain gate, holdback and suspension restrictions. Subscriptions are allowed monthly with a three-year lock up on subscriptions. The fund's assets are valued in accordance with valuations reported by the fund's sub-advisor or the fund's underlying investments or other independent third-party sources, although SEI, in its discretion, may use other valuation methods, subject to compliance with ERISA, as applicable. On an annual basis, as determined by the investment manager in its sole discretion, an independent valuation agent is retained to provide a valuation of the illiquid assets of the fund and of any other assets of the fund.

Funded Status. The following table provides a reconciliation of the changes in the fair value of plan assets and the actuarially computed benefit obligation for the years ended December 31, 2024 and 2023 and the funded status of the plans as of December 31, 2024 and 2023:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<i>2024</i>	<i>2023</i>	<i>2024</i>	<i>2023</i>	<i>2024</i>	<i>2023</i>
Change in Fair Value of Plan Assets:						
Fair Value of Plan Assets at January 1	\$ 321,887	\$ 305,953	\$ —	\$ —	\$ —	\$ —
Actual Return on Plan Assets	14,241	32,993	—	—	—	—
Company Contributions	—	—	1,219	1,253	1,566	2,971
Benefit Payments	(17,689)	(17,059)	(1,219)	(1,253)	(3,697)	(8,636)
Participant Premium Payments	—	—	—	—	2,131	5,665
Fair Value of Plan Assets at December 31	318,439	321,887	—	—	—	—
Change in Benefit Obligation:						
Benefit Obligation at January 1	310,513	300,354	11,802	12,216	29,361	48,698
Service Cost	3,785	3,606	—	—	478	551
Interest Cost	16,742	16,025	596	635	1,557	2,355
Benefit Payments	(17,690)	(17,059)	(1,218)	(1,253)	(3,696)	(8,636)
Participant Premium Payments	—	—	—	—	2,131	5,665
Plan Amendments	—	—	—	—	—	(17,038)
Liability Transfer	—	—	(369)	—	—	—
Actuarial (Gain) Loss	(7,818)	7,587	272	204	(638)	(2,234)
Benefit Obligation at December 31	305,532	310,513	11,083	11,802	29,193	29,361
Funded Status	\$ 12,907	\$ 11,374	\$ (11,083)	\$ (11,802)	\$ (29,193)	\$ (29,361)
Amounts Recognized in Balance Sheet at December 31:						
Noncurrent Assets	\$ 12,907	\$ 11,374	\$ —	\$ —	\$ —	\$ —
Current Liabilities	—	—	(1,227)	(1,212)	(2,547)	(2,405)
Noncurrent Liabilities and Deferred Credits	—	—	(9,856)	(10,590)	(26,646)	(26,956)
Net Asset (Liability)	\$ 12,907	\$ 11,374	\$ (11,083)	\$ (11,802)	\$ (29,193)	\$ (29,361)

The accumulated benefit obligation of our Pension Plan was \$280.7 million and \$281.3 million as of December 31, 2024 and 2023. The accumulated benefit obligation of our ESSRP was \$11.1 million and \$11.8 million as of December 31, 2024 and 2023.

The following assumptions were used to determine benefit obligations as of December 31, 2024 and 2023:

	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<i>2024</i>	<i>2023</i>	<i>2024</i>	<i>2023</i>	<i>2024</i>	<i>2023</i>
Discount Rate	5.70 %	5.57 %	5.60 %	5.53 %	5.61 %	5.53 %
Long-Term Rate of Compensation Increase	n/a	n/a	3.00 %	3.00 %	n/a	n/a
Participants to Age 39 ⁽¹⁾	4.50 %	4.50 %	n/a	n/a	n/a	n/a
Participants Ages 40 to 49 ⁽²⁾	4.50 %	4.50 %	n/a	n/a	n/a	n/a
Participants Age 50 and Older ⁽³⁾	3.75 %	3.75 %	n/a	n/a	n/a	n/a
Healthcare Cost Immediate Trend Rate	n/a	n/a	n/a	n/a	6.44 %	6.97 %
Healthcare Cost Ultimate Trend Rate	n/a	n/a	n/a	n/a	4.00 %	4.00 %
Year the Rate Reaches the Ultimate Trend Rate	n/a	n/a	n/a	n/a	2048	2048

⁽¹⁾ Amount reflects rate of compensation increases for both union and non-union employees.

⁽²⁾ Amount reflects rate of compensation increases for union employees. The rate of compensation increases for non-union employees is 3.50%.

⁽³⁾ Amount reflects rate of compensation increases for union employees. The rate of compensation increases for non-union employees is 3.00%.

The measurement of the plan assets or benefit obligation recognized for our Pension Plan, ESSRP and postretirement healthcare benefit plan included the following significant actuarial adjustments:

- For the Pension Plan, an increase in the discount rate in 2024 and 2023 reduced our obligation by \$4.6 million and \$2.1 million. Changes in plan participant census data decreased our benefit obligation by \$2.9 million in 2024. Actual returns on Pension Plan assets in 2024 were \$14.6 million, compared to an expected return of \$24.8 million, impacting our obligation by \$10.2 million.
- For the ESSRP, an increase in the discount rate in 2024 and 2023 reduced our obligation by less than \$0.1 million and \$0.1 million.
- For the postretirement healthcare plan, an increase in the discount rate in 2024 and 2023 reduced our obligation by \$0.2 million and \$1.3 million. Revised estimates of healthcare cost trends and participant contribution assumptions increased the benefit obligation by \$0.4 million in 2024. Changes in plan participant census data decreased our benefit obligation by \$0.9 million in 2024.

Net Periodic Benefit Cost. A portion of service cost may be capitalized as a cost of self-constructed property, plant and equipment. When recognized in the statements of comprehensive income, service cost is recognized within one of the components of operating expenses. Nonservice cost components of net periodic benefit cost may be deferred and recognized as a regulatory asset under the accounting guidance for regulated operations. When recognized in the statements of comprehensive income, nonservice cost components are recognized as nonservice cost components of postretirement benefits.

The following table includes the components of net periodic benefit cost (income) of our defined benefit pension plans and other postretirement benefits for the years ended December 31, 2024 and 2023:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	2024	2023	2024	2023	2024	2023
Service Cost	\$ 3,785	\$ 3,606	\$ —	\$ —	\$ 478	\$ 551
Interest Cost	16,742	16,025	596	635	1,557	2,355
Expected Return on Assets	(24,854)	(25,267)	—	—	—	—
Amortization of Prior Service Cost	—	—	—	—	(6,142)	(6,593)
Amortization of Net Actuarial Loss	153	—	—	—	—	—
Net Periodic Benefit Cost (Income)	\$ (4,174)	\$ (5,636)	\$ 596	\$ 635	\$ (4,107)	\$ (3,687)

The following table includes the impact of regulation on the recognition of periodic benefit cost (income) arising from pension and other postretirement benefits for the years ended December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Net Periodic Benefit (Cost) Income	\$ (7,685)	\$ (8,688)
Net Amount Amortized Due to the Effect of Regulation	1,367	1,225
Net Periodic Benefit (Cost) Income Recognized	\$ (6,318)	\$ (7,463)

The following assumptions were used to determine net periodic benefit cost for the years ended December 31, 2024 and 2023:

	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	2024	2023	2024	2023	2024	2023
Discount Rate	5.57 %	5.51 %	5.53 %	5.51 %	5.53 %	5.52 %
Long-Term Rate of Return on Plan Assets	7.00 %	7.00 %	n/a	n/a	n/a	n/a
Long-Term Rate of Compensation Increase	n/a	n/a	3.00 %	3.00 %	n/a	n/a
Participants to Age 39	4.50 %	4.50 %	n/a	n/a	n/a	n/a
Participants Ages 40 to 49	4.00 %	3.50 %	n/a	n/a	n/a	n/a
Participants Ages 50 and Older	3.38 %	2.75 %	n/a	n/a	n/a	n/a

We develop our estimated discount rate through the use of a hypothetical bond portfolio method. This method derives the discount rate from the average yield of a collection of high credit quality bonds which produce cash flows similar to our anticipated future benefit payments. We estimate the assumed long-term rate of return on plan assets based primarily on asset category studies using historical market return and volatility data with forward-looking estimates based on existing financial market conditions and forecasts of capital markets. Modest excess return expectations versus some market indices are incorporated into the return projections based on the actively managed structure of the investment programs and their records of achieving such returns historically.

The following table presents the amounts not yet recognized as components of net periodic benefit cost as of December 31, 2024 and 2023:

(in thousands)	Pension Benefits (Pension Plan)		Pension Benefits (ESSRP)		Postretirement Benefits	
	2024	2023	2024	2023	2024	2023
Regulatory Assets (Liabilities):						
Unrecognized Prior Service Cost (Credit)	\$ —	\$ —	\$ —	\$ —	\$ (12,703)	\$ (18,845)
Unrecognized Actuarial Loss	87,868	85,227	292	1,061	1,121	1,759
Net Regulatory Assets (Liabilities)	87,868	85,227	292	1,061	(11,582)	(17,086)
Accumulated Other Comprehensive Income (Loss):						
Unrecognized Prior Service Cost	—	—	—	—	—	—
Unrecognized Actuarial Gain (Loss)	—	—	(2,631)	(1,591)	—	—
Total Accumulated Other Comprehensive Income (Loss)	\$ —	\$ —	\$ (2,631)	\$ (1,591)	\$ —	\$ —

Cash Flows. We did not make any contributions to our Pension Plan in 2024 or 2023. As of December 31, 2024, we had no minimum funding requirements for our Pension Plan. Contributions to our ESSRP and postretirement healthcare plan are equal to the benefits paid to plan participants.

The following reflects anticipated benefit payments to be paid in each of the next five years and in the aggregate for the five-year period thereafter under our pension plans and postretirement healthcare plan:

(in thousands)	2025	2026	2027	2028	2029	2030-2034
Projected Pension Plan Benefit Payments	\$ 18,754	\$ 19,269	\$ 19,736	\$ 20,296	\$ 20,841	\$ 108,270
Projected ESSRP Benefit Payments	1,259	1,216	1,108	1,048	1,119	4,535
Projected Postretirement Benefit Payments	2,547	2,543	2,507	2,421	2,449	11,694
Total	\$ 22,560	\$ 23,028	\$ 23,351	\$ 23,765	\$ 24,409	\$ 124,499

401K Plan

We sponsor a 401K plan for the benefit of all of our employees. Contributions made to this plan totaled \$4.9 million for 2024 and \$3.9 million for 2023.

9. Asset Retirement Obligations

We have recognized Asset Retirement Obligations (AROs) related to our coal-fired generation plants, natural gas combustion turbines, solar facility, and wind turbines. The cost of AROs include items such as site restoration, closure or removal of ash pits, and removal of certain structures, generators, asbestos and storage tanks. We have other legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. We have no assets legally restricted for the settlement of any AROs. As of December 31, 2024 and 2023, \$0.1 million and \$0.1 million, respectively, was included in other current liabilities and \$42.1 million and \$36.4 million, respectively, was included in other noncurrent liabilities in the balance sheets related to AROs.

A reconciliation of the carrying amounts of AROs for the years ended December 31, 2024 and 2023 is as follows:

(in thousands)	2024	2023
Beginning Balance	\$ 36,477	\$ 25,182
New Obligations Recognized	2,991	4,506
Adjustments Due to Revisions in Cash Flow Estimates	1,098	8,394
Accrued Accretion	1,676	1,191
Settlements	(79)	(2,796)
Ending Balance	\$ 42,163	\$ 36,477

Coal Combustion Residual Regulations

In May 2024, the Environmental Protection Agency (EPA) published a final rule amending coal combustion residual (CCR) regulations. The final rule introduces new requirements for the management of coal ash at active coal-fired power plants and inactive coal-fired power plants with a legacy surface impoundment. The regulations impose new requirements including groundwater monitoring, closure standards, post-closure care obligations and potential remediation activities. At this time, we do not believe there are any significant new requirements which are applicable to our coal-fired power plants, except for Big Stone Plant. During the fourth

quarter of 2024, a site evaluation was performed at Big Stone Plant to assess the presence and estimated volumes of coal ash stored at the facility. Based on this and our assessment of the regulations, we believe the plant will be impacted by the new requirements. As of December 31, 2024, we recognized \$3.0 million of additional liabilities for new obligations resulting from the EPA's final CCR rule for costs associated with coal ash removal and groundwater monitoring we expect to incur in the future. The final rule requires facility evaluations to be performed in the future. Revisions to our estimated compliance costs or further obligations could be identified through the process of performing the additional evaluations. Should such revisions be necessary or if additional cost obligations are identified, we will update our cash flow estimates and resulting retirement obligation at that time.

10. Income Taxes

Income before income taxes for the years ended December 31, 2024 and 2023 consists entirely of domestic earnings.

The provision for income taxes charged to income for the years ended December 31, 2024 and 2023 consisted of the following:

<i>(in thousands)</i>	2024	2023
Current		
Federal Income Taxes	\$ (13,769)	\$ (20,376)
State Income Taxes	(2,280)	(2,669)
Deferred		
Federal Income Taxes	6,671	17,337
State Income Taxes	8,431	7,945
Tax Credits		
North Dakota Wind Tax Credit Amortization, Net of Federal Tax	(586)	(586)
Investment Tax Credit Amortization	(11)	(3)
Total	\$ (1,544)	\$ 1,648

The reconciliation of the statutory federal income tax rate to our effective tax rate for each of the years ended December 31, 2024 and 2023 is as follows:

	2024		2023	
Income Taxes at Federal Statutory Rate	\$ 18,778	21.0 %	\$ 18,075	21.0 %
Increases (Decreases) in Tax from:				
State Taxes on Income, Net of Federal Tax	4,441	5.0	4,327	5.0
Production Tax Credits (PTCs)	(20,106)	(22.5)	(17,394)	(20.2)
Amortization of Excess Deferred Income Taxes	(2,788)	(3.1)	(2,205)	(2.6)
North Dakota Wind Tax Credit Amortization, Net of Federal Tax	(586)	(0.7)	(586)	(0.7)
Allowance for Equity Funds Used During Construction	(726)	(0.8)	(312)	(0.4)
Other, Net	(557)	(0.6)	(257)	(0.3)
Income Taxes at Effective Tax Rate	\$ (1,544)	(1.7)%	\$ 1,648	1.9 %

PTCs, North Dakota wind tax credits and excess deferred income taxes related to the federal tax rate reduction in the 2017 Tax Cuts and Jobs Act are returned to customers as a reduction of the rates they are charged and result in a reduction of operating revenues.

Deferred tax assets and liabilities were composed of the following on December 31, 2024 and 2023:

<i>(in thousands)</i>	<i>2024</i>	<i>2023</i>
Deferred Tax Assets		
Employee Benefits	\$ 18,988	\$ 20,618
Regulatory Liabilities	52,664	56,479
Tax Credit Carryforwards	39,717	37,791
Cost of Removal	35,374	32,993
Asset Retirement Obligations	10,948	9,494
Other	5,772	5,291
Total Deferred Tax Assets	163,463	162,666
Deferred Tax Liabilities		
Differences Related to Property	(357,347)	(332,249)
Retirement Benefits Regulatory Asset	(22,892)	(22,458)
Pension Expense	(26,393)	(25,264)
Other	(2,292)	(5,685)
Total Deferred Tax Liabilities	(408,924)	(385,656)
Deferred Income Taxes	\$ (245,461)	\$ (222,990)

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns.

As of December 31, 2024, we had net operating loss carryforwards for state tax purposes totaling \$2.3 million that expire between 2029 and 2037, and state tax credits totaling \$18.3 million which expire between 2040 and 2043. Under the tax sharing agreement between Otter Tail Corporation and OTP, we are paid on an annual basis for the use of these tax attributes in the consolidated income tax returns. Accordingly, these tax assets will not be available to reduce future cash taxes.

As of December 31, 2024 and 2023, we had no unrecognized tax benefits. As of December 31, 2024, with limited exceptions, we are no longer subject to examinations by taxing authorities for tax years prior to 2021 for federal and North Dakota income taxes and prior to 2020 for Minnesota state income taxes.

11. Commitments and Contingencies

Commitments

Electric Utility Capacity and Energy Requirements. We have commitments for the purchase of capacity and energy requirements under contractual agreements, including wind power purchase agreements extending into 2048. Generally, the terms of our wind power purchase agreements require us to purchase all of the electricity generated by a particular wind farm, but do not include fixed or minimum payments. The required payments are variable and the amounts due are determined based upon the amount of capacity available or electricity generated. Capacity and energy requirement costs under these agreements totaled \$6.0 million and \$5.6 million for the years ended December 31, 2024 and 2023.

Coal Purchase Commitments. We have contracts providing for the purchase and delivery of our coal requirements. Our current coal purchase agreement with CCMC for Coyote Station expires on December 31, 2040. All of Coyote Station's coal requirements for the period covered must be purchased under this agreement. The agreement is structured so that the price of the coal covers all of CCMC's operating, financing and future mine reclamation costs. In the table below, we have estimated the future payments to be made under the terms of the agreement until its maturity. We have an agreement for the purchase of Big Stone Plant's coal requirements through December 31, 2026. There is no fixed minimum purchase requirement, and no amounts for this agreement have been included in the table below; however, under this agreement all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement. Coal purchase costs under these two agreements totaled \$44.7 million and \$43.7 million for the years ended December 31, 2024 and 2023.

Land Easement Payments. We have commitments to make payments for land easements not classified as leases. The contractual terms of these easements are generally 99 years or do not have a stated maturity date; however, per the terms of the agreements, our requirement to make payments ends once we cease use of the land. As such, in the table below, we have included payments under these easements through the estimated useful lives of the facilities associated with the easement. The commitments under these arrangements extend into 2055 and total approximately \$62.0 million. Land easement costs under these agreements totaled \$1.8 million and \$1.8 million for the years ended December 31, 2024 and 2023.

Other Commitments. As of December 31, 2024, we had commitments under contracts for plant maintenance, software subscriptions and other services extending into 2046 which totaled approximately \$8.0 million.

Our future commitments as of December 31, 2024 were as follows:

<i>(in thousands)</i>	<i>Coal Purchase Commitments</i>	<i>Land Easement Payments</i>	<i>Other Commitments</i>
2025	\$ 24,192	\$ 1,897	\$ 550
2026	24,416	1,902	474
2027	25,127	1,941	481
2028	25,859	1,981	489
2029	27,102	2,021	272
Beyond 2029	314,713	52,261	5,758
Total	\$ 441,409	\$ 62,003	\$ 8,024

Solar Development. On October 30, 2024, we entered into an agreement to acquire the assets of a solar facility currently under development. The assets to be acquired include real property rights and interests, interconnection agreements, state and local permits, and other development assets. Per the agreement, the purchase price is equal to \$23.6 million, plus the reimbursement of certain interconnection costs and costs to purchase and store the main power transformer. Closing of the transaction is expected to occur in late 2025 or early 2026, and remains subject to certain conditions to close, including regulatory and other approvals. We would be subject to a termination fee of up to \$5.0 million if the seller has satisfied all required conditions to close but the transaction is not consummated.

Contingencies

FERC ROE. In November 2013 and February 2015, customers filed complaints with FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO tariff rate. FERC issued an order on November 19, 2020, which adopted a revised ROE methodology and set the base ROE at 10.02% (10.52% with an adder) effective for the fifteen-month period from November 2013 to February 2015 and on a prospective basis beginning in September 2016. The order also dismissed any complaints covering the period from February 2015 to May 2016. On August 9, 2022, the U.S. Court of Appeals for the District of Columbia Circuit vacated the FERC order citing a lack of reasoned explanation by FERC in its adoption of its revised ROE methodology as outlined in its November 2020 order and remanded the matter to FERC to reopen the proceedings.

On October 17, 2024, FERC issued an Order on Remand modifying its ROE methodology and establishing a base ROE of 9.98% (10.48% with an adder) effective for the fifteen-month period from November 2013 to February 2015 and on a prospective basis beginning in September 2016, and required MISO transmission owners to provide refunds to customers for collections in excess of the base ROE of 9.98% for the applicable period, plus interest. In addition, FERC concluded the evidentiary record continues to support the ROE established for the period from February 2015 to May 2016.

Prior to FERC's Order on Remand, we had deferred recognition of certain revenues and recognized a refund liability which reflected the amount previously collected under the MISO tariff rate that we anticipated would be refunded to customers. Our previous estimated refund amount was larger than the actual amount ordered by FERC in the Order on Remand and was therefore reduced, which resulted in a pre-tax benefit of \$2.5 million recognized in our consolidated statements of income for the year ended December 31, 2024. The balance of the recorded refund liability as of December 31, 2024 was \$0.5 million.

Self-Funding of Transmission Upgrades for Generator Interconnections. FERC has granted transmission owners within MISO and other regional transmission organizations (RTOs) the unilateral authority to determine the funding mechanism for interconnection transmission upgrades that are necessary to accommodate new generation facilities connecting to the electrical grid. Under existing FERC orders, transmission owners can unilaterally determine whether the generator pays the transmission owner in advance for the transmission upgrade or, alternatively, the transmission owner can elect to fund the upgrade and recover over time from the generator the cost of and a return on the upgrade investment (a self-funding). FERC's orders granting transmission owners this unilateral funding authority have been judicially contested on the basis that transmission owners may be motivated to discriminate among generators in making funding determinations. In the most recent judicial proceedings, the petitioners argued to the U.S. Court of Appeals for the District of Columbia that FERC did not comply with a previous judicial order to fully develop a record regarding the risk of discrimination and the financial risk absorbed by transmission owners for generator-funded upgrades. In December 2022, the Court of Appeals ruled in favor of the petitioners remanding the matter to FERC, instructing the agency to adequately explain the basis of its orders. The Court of Appeals decision did not vacate transmission owners' unilateral funding authority.

In June 2024, FERC issued an Order to Show Cause proceeding against four RTOs, including MISO. Within its order, FERC indicates that the transmission tariffs of the RTOs appear to be unjust, unreasonable, and unduly discriminatory or preferential because they allow transmission owners to unilaterally elect transmission owner self-funding, which may increase costs, impose barriers to transmission interconnection and result in undue discrimination among interconnection customers.

The order required each RTO to submit filings to either 1) show cause as to why the transmission tariff remains just and reasonable and not unduly discriminatory or preferential, or 2) to explain what changes to the tariff it believes would remedy the identified concerns. FERC has received a number of responses to its Order to Show Cause. In September 2024, in separate filings, MISO and transmission owners within MISO, including OTP, filed responses outlining the reasons why the self-funding option remains just and reasonable and not unduly discriminatory or preferential. Other responses have been provided by other RTOs, individual transmission owners, developers of renewable generation facilities and other interested parties.

As a transmission owner in MISO, we have exercised our authority and elected to self-fund previous transmission upgrades necessary to accommodate new system generation. Under such an election, we are recovering the cost of the transmission upgrade and a return on that investment from the generator over a contractual period of time. Should the resolution of this matter eliminate transmission owners' unilateral funding authority on either a prospective or retrospective basis, our financial results would be impacted. We cannot at this time reasonably predict the outcome of this matter given the uncertainty as to how FERC may ultimately decide on the matter after RTOs' filings in response to the Order to Show Cause.

Other Contingencies. We are party to litigation and regulatory matters arising in the normal course of business. We regularly analyze relevant information and, as necessary, estimate and record accrued liabilities for legal, regulatory enforcement and other matters in which a loss is probable of occurring and can be reasonably estimated. We believe the effect on our operating results, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2024, other than those discussed above, will not be material.

12. Accumulated Other Comprehensive Income (Loss)

Our other comprehensive income (loss) consists of unamortized actuarial losses and prior service costs related to pension and other postretirement benefits. The income tax expense or benefit associated with amounts reclassified from accumulated other comprehensive income (loss) and reflected in the statements of comprehensive income are recognized in the same period as the amounts are reclassified.

The following table shows the changes in accumulated other comprehensive income (loss) for the years ended December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Balance, Beginning of Period	\$ (1,177)	\$ (1,086)
Other Comprehensive Income (Loss) Before Reclassifications, net of tax	972	(115)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) ⁽¹⁾	(1,743)	24
Total Other Comprehensive Income (Loss)	(771)	(91)
Balance, End of Period	\$ (1,948)	\$ (1,177)

⁽¹⁾ Included in the computation of net periodic pension and other postretirement benefit costs. See Note 8 for further information.

13. Dividend Restrictions

Our credit agreements contain restrictions on the payment of cash dividends upon a default or event of default, including failure to maintain certain financial covenants. As of December 31, 2024, we were in compliance with these financial covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes “funds properly included in a capital account” is undefined in the Federal Power Act and the related regulations; however, the FERC has consistently interpreted the provision to allow dividends to be paid as long as i) the source of the dividends is clearly disclosed, ii) the dividend is not excessive and iii) there is no self-dealing on the part of corporate officials.

The Minnesota Public Utilities Commission (MPUC) indirectly limits the amount of dividends we can pay to Otter Tail Corporation by requiring an equity-to-total-capitalization ratio between 47.2% and 57.7%, with total capitalization not to exceed \$2.2 billion based on our capital structure requirements as of December 31, 2024. As of December 31, 2024, our equity-to-total-capitalization ratio, including short-term debt, was 53.1% and our net assets restricted from distribution totaled approximately \$834.5 million.

14. Derivative Instruments

We enter into derivative instruments to manage our exposure to future commodity price variability, specifically future wholesale energy and natural gas prices, and reduce volatility in prices for our retail customers. These derivative instruments are not designated as qualifying hedging transactions but provide for an economic hedge against future price variability. These instruments are recorded at fair value on our balance sheets on a gross basis with assets and liabilities presented separately. In accordance with rate-making and cost recovery processes, we recognize a regulatory asset or liability to defer losses or gains from derivative activity until settlement of the associated derivative instrument.

As of December 31, 2024 and 2023, we had outstanding pay-fixed, receive-variable swap agreements. The contracts outstanding as of December 31, 2024 had various settlement dates throughout 2025. The following presents the notional amounts and fair value of our derivative instruments as of December 31, 2024 and 2023:

<i>(in thousands)</i>	2024	2023
Megawatt hours of electricity	167	187
Derivative Liabilities:		
Other Current Liabilities	\$ 1,989	\$ 4,210
Other Noncurrent Liabilities	—	—
Total Derivative Liabilities	\$ 1,989	\$ 4,210

During the years ended December 31, 2024 and 2023, contracts matured and were settled in an aggregate amount of a \$3.5 million loss and a \$16.5 million loss, respectively. Gains and losses recognized on the settlement of derivative instruments are returned to, or recovered from, our electric customers through fuel recovery mechanisms in each state. When recognized in the statements of comprehensive income, these gains or losses are included in electric purchased power. Gains or losses related to the settlement of derivative instruments are included in cash flows from operation in the statements of cash flows.

15. Fair Value Measurements

The following tables present our assets and liabilities measured at fair value on a recurring basis as of December 31, 2024 and 2023 classified by the input method used to measure fair value:

	<i>Level 1</i>	<i>Level 2</i>	<i>Level 3</i>
December 31, 2024			
Liabilities:			
Derivative Instruments	\$ —	\$ 1,989	\$ —
Total Liabilities	\$ —	\$ 1,989	\$ —
December 31, 2023			
Liabilities:			
Derivative Instruments	\$ —	\$ 4,210	\$ —
Total Liabilities	\$ —	\$ 4,210	\$ —

The level 2 fair value measurements for derivative instruments are determined by using inputs such as forward electric commodity prices, adjusted for location differences. These inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

In addition to assets and liabilities recorded at fair value on a recurring basis, we also hold financial instruments that are not recorded at fair value in the balance sheets but for which disclosure of the fair value of these financial instruments is provided. The following reflects the carrying value and estimated fair value of these assets and liabilities as of December 31, 2024 and 2023:

<i>(in thousands)</i>	<i>December 31, 2024</i>		<i>December 31, 2023</i>	
	<i>Carrying Amount</i>	<i>Fair Value</i>	<i>Carrying Amount</i>	<i>Fair Value</i>
Assets:				
Cash and Cash Equivalents	\$ 12	\$ 12	\$ 32	\$ 32
Total	12	12	32	32
Liabilities:				
Short-Term Debt	69,615	69,615	81,422	81,422
Long-Term Debt	863,834	729,952	744,210	635,398
Total	\$ 933,449	\$ 799,567	\$ 825,632	\$ 716,820

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that fair value:

Cash Equivalents: The carrying amount approximates fair value because of the short-term maturity of these instruments. Fair value is determined based on quoted prices in active markets, a Level 1 fair value input.

Short-Term Debt: The carrying amount approximates fair value because the debt obligations are short-term in nature and the balances outstanding are subject to variable rates of interest which reset frequently, a Level 2 fair value input.

Long-Term Debt: The fair value of long-term debt is estimated based on current market indications for borrowings of similar maturities with similar terms, a Level 2 fair value input.

16. Related Party Transactions

Included in the amounts presented in the accompanying balance sheets and statements of comprehensive income as of and for the years ended December 31, 2024 and 2023 are the following related party transaction balances attributable to transactions with Otter Tail Corporation:

<i>(in thousands)</i>	2024		2023	
Accounts Receivable	\$	7	\$	7
Accounts Payable		5,223		2,415
Operating Revenues		18		26
Operating and Maintenance Expenses	\$	14,821	\$	13,743

Operating and maintenance expenses predominantly relate to the allocation of corporate overhead expenses from Otter Tail Corporation, including items such as labor, professional services, subscriptions, information technology and general office expenses. Operating revenues primarily arise from rent charged to Otter Tail Corporation for office space usage.

Otter Tail Corporation pays OTP for certain tax credits and other tax benefits it generates, which are realized through the filing of Otter Tail Corporation's consolidated tax returns. We received \$15.4 million and \$24.3 million during the years ended December 31, 2024 and 2023, respectively, from Otter Tail Corporation in exchange for these tax credits and other tax benefits. In February 2025, OTP received payments totaling \$21.6 million from Otter Tail Corporation in exchange for certain tax credits and other tax benefits.

The Otter Tail Power Company Foundation is an independent not-for-profit charitable entity affiliated with OTP and is not included in our financial statements. Contribution obligations to the foundation totaling \$0.5 million and \$1.5 million were recognized as of December 31, 2024 and 2023, respectively. Cash contributions paid to the foundation during the years ended December 31, 2024 and 2023 were \$1.5 million and \$1.3 million, respectively.